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A Model to Relate Environmental Variation to NPDES Permit Violations at Thermoelectric Facilities on the Taunton River

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A MODEL TO RELATE ENVIRONMENTAL VARIATION TO NPDES PERMIT VIOLATIONS AT THERMOELECTRIC FACILITIES ON THE TAUNTON RIVER

A Dissertation Presented

by

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ABSTRACT

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June 2012

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Large thermoelectric facilities are issued permits to discharge high volume, high temperature effluents as part of the National Pollutant Discharge Elimination System (NPDES). Once-through cooled power plants are especially dependent on large quantities of cool water to operate. When ambient temperatures are high or streamflow is very low, power plant managers must reduce (i.e., “dial back”) energy generation in order to avoid violating their NPDES permit limitations. Sudden dial-back can have human health impacts when electricity is no longer available to provide space cooling or other vital services. A preferred system of electricity and environmental management would reduce the probability of future violations and/or dial-back by explicitly recognizing the facilities for which those events are highly likely.

An original statistical model is presented and used to answer the following research questions: 1) Do electricity demand and natural environmental conditions influence withdrawal rates and effluent temperatures at once-through thermoelectric facilities? 2) Is it possible to estimate past withdrawal rates and effluent temperatures where reported observations are unavailable? 3) In the future, how often will power plant managers face the decision to dial-back generation or violate their plant's discharge permit? 4) What can be done to avoid such decisions and the resulting negative impacts?

Two facilities in Massachusetts were chosen as representative case studies. Using public records, several decades of daily and monthly observations of environmental variables (e.g. ambient air temperature, streamflow) and monthly energy generation were tested against monthly observations of facility water withdrawal rates and maximum discharge temperatures using a multiple linear regression (MLR) approach.

The MLR model successfully estimated monthly maximum discharge temperatures for both facilities using monthly average of daily high air temperatures and monthly net electricity generation. The model was used to identify months in the past when violations or dial-back are likely to have occurred, as well as months in the future when each plant is expected to dial-back or violate its permit as ambient air temperatures continue to rise. Solutions are presented that reduce the number of predicted violations, meet consumer electricity demand to the greatest extent possible, and reduce the chances of sudden dial-back.

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DEDICATION

To my parents, Clark and Cheryl

TABLE OF CONTENTS

CHAPTER Page

LIST OF FIGURES

Figure Page

Figure Page

Figure Page

Figure Page

Figure Page

LIST OF TABLES

Table Page

Table Page

LIST OF EQUATIONS

Equation Page

Equation	Page

Equation Page

LIST OF APPENDIX TABLES

Table Page

Table Page

Table Page

Table Page

LIST OF ABBREVIATIONS

AEO	Annual Energy Outlook
AOGCM	atmosphere-ocean general circulation model
ASME	American Society of Mechanical Engineers
BIP	balanced, indigenous populations
BIT	bituminous coal
BPJ	best professional judgment
BTU	British thermal unit
CA	prime mover code for the steam part of a NGCC system
CAP	compliance action cost
CES	clean energy standard
CFR	Code of Federal Regulations
cfs	cubic feet per second
CHP	combined heat and power
CWA	Clean Water Act
DFO	distillate fuel oil
DMR	Discharge Monitoring Report
DOE	Department of Energy
DSM	demand side management
ECHO	Enforcement and Compliance History Online
EIA	Energy Information Administration
EPA	Environmental Protection Agency
gpm	gallons per minute
GWPC	Groundwater Protection Council
HU	hydrologic unit
HWA	hemlock wooly adelgid
ICIS	Integrated Compliance Information System
IEA	International Energy Agency
ISO	independent service operator
JF	jet fuel
kWh	kilowatt·hour
MassDEP	Massachusetts Department of Environmental Protection
MA-SYE	Massachusetts Sustainable-Yield Estimator
mgd	million gallons per day
MLR	multiple linear regression
MW	megawatt
MWh	megawatt·hour
NCDC	National Climate Data Center
NECIA	Northeast Climate Impacts Assessment
NETL	National Energy Technology Lab
NG	natural gas
NGCC	natural gas combined cycle

NHESP	Natural Heritage and Endangered Species Program
NPDES	National Pollution Discharge Elimination System
NREL	National Renewable Energy Lab
PCS	Permit Compliance System
PDF	probability density function
RFO	residual fuel oil
SE	Standard Error
SEP	supplemental environmental project
TVA	Tennessee Valley Authority
UCS	Union of Concerned Scientists
U.S.C	United States Code

CHAPTER 1

INTRODUCTION

Water and energy

Water is essential for survival. It is central to our agricultural and sanitation systems. We need clean water to drink and natural ecosystems need clean water to exist. Many parts of the United States have long enjoyed relatively abundant water resources, but concerns over the availability of water supplies, in terms of both distribution and quantity, are growing. For many, the worry can be traced to the natural and increasing volatility of the global hydroclimatic system. Others point to a flawed U.S. water management setting in which collective cries for enhanced water security are muted by equally boisterous protests about the high costs involved. Proper surface and groundwater protection promotes economic progress, human health, and environmental wellbeing. It is also expensive.

By the early 20th century, reliable electricity and liquid fuel supplies became necessities for the prosperity of the developed world, driving unprecedented population growth that continues in many areas today (Klein, 2008). For people living at the turn of the last century, local water scarcity was a mere footnote, and in some cases wholly ignored by policymakers at the highest levels of government. Westward expansion and the increase of total energy consumption could not—would not—be stopped. And what was largely unapparent to late 19th and early 20th century Americans is now obvious: energy demands are increasing (IEA, 2010) and they are doing so in tandem with water demands (Shiklomanov, 1998).

By the 1940's, hydroelectric dam building was the most common method of delivering reliable water and energy supplies to a power hungry public. Dams served the dual purpose of freshwater reservoir creation and electricity generation (Solomon, 2010). At that time, the connection between water and energy was tangible to even the most casual observer, but the continued availability of the water was rarely questioned. Dam engineers and planning agencies were aware of the importance of having adequate freshwater inputs, but assumed that rainfall and snowmelt would be enough for all uses, including power production. As the U.S. Army Corps of Engineers and the U.S. Bureau of Reclamation slowly ran out of suitable dam sites and as the costs of building dams steadily increased (Reisner, 1986), different fuels were sought to meet the ravenous and increasing consumption of a post-World War II United States. The percentage of electricity produced in the U.S. by hydroelectric sources declined as new nuclear and fossil fuel plants were constructed.

Eventually, colossal civil engineering works like the Hoover Dam fell out of the public consciousness and only recently have long term water constraints become significant factors for consideration during the permitting and siting of thermoelectric power plants (Sovacool and Sovacool, 2009a). Although it is less visible today, the nexus between our water and energy systems retains its significance. In fact, 39 percent of all fresh water withdrawals in the U.S. are used for thermoelectric cooling (Hightower et al., 2006).

Furthermore, a growing body of evidence suggests that a "business as usual" course for energy planning in the U.S. will pit water resources needed for thermoelectric power plant cooling and auxiliary services against water needed for agricultural and aesthetic irrigation, drinking, sanitation, and environmental health (Sovacool and Sovacool, 2009b). The water vulnerabilities associated with inadequate energy planning are not limited to historically parched regions (e.g. the Southwest). For instance, in 1979, the U.S. Water Resources Council, designated the Northeastern U.S. as a low vulnerability region for water supply and demand indicators (U.S. Water Resources Council, 1979), but a wealth of scientific and anecdotal information gathered since then reveals that Thermoelectric Energy's dependences and impacts on water supplies can be substantial, and that they are dictated by local conditions. A period of cold, wet weather in New England may offer no relief for a town in Massachusetts that has a hydrologically unique microclimate or that has energy demands which its mid-20th century energy planners could not imagine.

The following sections offer a summary of the basics of thermoelectric energy generation, its water requirements, and associated environmental impacts. Attempts to mitigate some of the environmental impacts through federally mandated permitting procedures are also discussed, as are a few of the unintended consequences of those regulations. The summary begins with an outline of the principles which have guided this research, a formal statement of the hypothesis, and a synopsis of the goals of each research phase.

Research principles, hypothesis, and goals

The following research was guided by a variety of principles that appear to be fundamental to the thermoelectric industry:

1. Conventional thermoelectric plants need substantial quantities of water for cooling during normal operation and can worsen emergency conditions during times of water scarcity (Sovacool, 2009).
2. The best solutions to water monitoring (e.g. installing flow meters and temperature gauges that report real-time data to regulatory agencies) may be completely impractical due to expense and institutional resistance to change.
3. Self-reported data by plants represents the best public data available, but it comes with the qualifications that power plant operators have a strong incentive to round numbers in their favor and that some values (e.g. average water withdrawal rates) are based on estimations (Dziegielewski and Bik, 2006).
4. Location plays a central role in determining a power plant's thermodynamic efficiency, water use efficiency (Macknick et al., 2011), and vulnerability to environmental variation.
5. In addition to location, a power plant's sensitivity to environmental variation and potential for forced deratings depends on plant design and the stringency of its environmental permit constraints (Miller et al., 1992).
6. Withdrawal rates and effluent temperatures are not strictly determined by predictable physical laws, but are subject to the unforeseeable complexities inherent in human-run, high technology systems (Yang and Dziegielewski, 2007).
7. In some cases, statistical models can sufficiently capture correlations that lead to better management practices in the face of future uncertainty.
8. With proper planning, a power plant can generate electricity to meet demand, will not violate its permits, and will not degrade the environment.
9. Ultimately, environmental health is the best indicator of the limits under which power plants should operate (Frankić, 2004).

With the hope of improving the current energy-water paradigm, this research includes a facility-scale evaluation of the adequacy of existing thermoelectric water use permit conditions for two power plants in Southeastern Massachusetts, while providing a methodology for doing similar, scale-appropriate assessments at other once-through cooled facilities. Using historical data at a monthly timescale, the research identifies the measurable variables that are most relevant to assessing whether or not each facility could reasonably have violated its water use permit or have dialed back its generation in order to avoid violating its permit.

A violation (i.e., alleged violation) occurs when a plant's effluent exceeds chemical or thermal limitations for some minimum amount of time. For practical reasons, most facilities are afforded a "buffer zone" of acceptance, so that short-lived withdrawal or thermal violations go unpunished, unless the frequency or extent of the violations becomes conspicuous. One must only look to the Environmental Protection Agency's PCS and ICIS databases of water use information for regulated facilities for a reasonable depiction of how alleged violations are handled. For most plants, violation markers significantly outnumber informal and formal citations and fines. The research provides a model for estimating the likelihood of past and future dial back and/or permit violation events, and which allows for the incorporation of various responses (e.g. physical, regulatory, economic) to reduce the likelihood of future undesirable events of this type.

The model is used to test the following hypothesis:

> Environmental variables and energy generation values can be used to estimate water use rates and effluent temperature at once-through cooled thermoelectric facilities. Model-generated effluent temperature and water use violations outnumber historical alleged violations.
>
> Regulatory response mechanisms may be incorporated into a model of each facility-environment system to reduce both the number of predicted dial-back events (i.e., reduced capacity events) and the number of predicted permit violations.

Technically, the research delivers data and tools for assembling new National Pollutant Discharge Elimination System (NPDES) permits and for reviewing existing NPDES permits of open-loop thermoelectric plants, with a view to addressing the unintended energy consequences of the Clean Water Act. A new methodology that brings managers from field measurements to positive environmental action and energy planning may help Massachusetts and other states to avoid the many costs associated with aquatic habitat degradation and increasingly unreliable electricity supply.

The research was divided into three phases. During Phase I, research was conducted to identify appropriate and feasible case studies. Long term, site-specific environmental and energy generation data were gathered and compiled for each of the case studies in order to investigate the specific environmental and industrial context of the plants. Based on the aggregated data, multiple linear regression (MLR) models were developed to relate environmental and energy generation conditions at each plant to water use rates and effluent temperature parameters. For each plant, the number of observed alleged permit violations was compared to model-generated violations to identify months when power plant operators may have been faced with the decision to dial back their generation or violate their NPDES permit conditions.

Upon the completion of Phase I, ambient air temperature and energy generation values within the model were changed to reflect predicted future environmental and energy generation conditions under a range of climate change scenarios and electricity supply forecasts for a 20- or 30-year time period. The purpose of Phase II was to determine the conditions under which each facility might expect to violate its permit or be forced to decrease its generation at certain times in the future if it were to remain open.

A recent study by Roy et al. (2010) compiled 16 major climate change models, which offer a wide range of air temperature increase scenarios. Climate change models that are regional or specific to the Northeastern U.S. were also used. The other important component to predicting when permits might be violated or when power plant operators may be forced to dial back is energy generation, which is described using yearly Energy Information Administration and International Energy Agency outlooks, as well as regional industry-generated demand models. During Phase II, predicted increases or decreases in energy demand are represented in the model as increased or decreased electricity generation values (megawatt·hours, MWh, per month). A prevailing view in the energy and water research community is that, by 2025, the electricity industry will be strained by water shortages due to population growth, thermoelectric power plant capacity additions, and an increasing frequency of summertime droughts (Sovacool and Sovacool, 2009b). Phase II of the research tests this notion about water constraints at the ground level, and evaluates whether water supply constraints or permit related constraints represent the most immediate risks for energy generation in the study area. Water supply constraints are what might be referred to as “hard” limits: once-through facilities cannot operate without water. But permit constraints, such as withdrawal rate and discharge temperature limitations, may transition from “soft” limits to hard limits if and when plant operators decide to reduce their electricity generation.

A variety of regulatory and economic strategies may be used to drive down energy demand at these facilities and to help power plants prepare for increasing ambient temperatures, with a view to reducing the chances of future permit violations or hazardous reductions in electricity generation. As early as 1965, researchers began investigating the connections between price changes of necessary inputs (e.g. fuel, water) on the withdrawal rates of thermoelectric facilities, and found significant correlations (Dziegielewski and Bik, 2006). More recent studies suggest that accurate electricity pricing (i.e. pricing which includes water-related impacts and risks) would be enough to improve the efficiency of the thermoelectric energy industry, provide customers with more accurate price signals, and would reduce wasteful energy consumption (Sovacool, 2009). Such reforms would decrease the overall water-related strains faced by electric facilities now and in the future.

During the last phase of research, practical regulatory responses were incorporated in the MLR models to test if future violation and/or dial back events can be avoided. For the most part, the final phase of the research was informed by a series of interviews and discussion groups that were conducted by the author at the two national conferences that offered the greatest opportunity for in-person discussion with environmental experts, government regulators, and energy industry representatives on the topics of water use by thermoelectric facilities and NPDES permitting. The first was hosted by the Groundwater Protection Council (GWPC) and took place in Atlanta from September 24-28. The second was hosted by the American Society of Mechanical Engineers (ASME) and took place in Denver from November 11-17. They are among a very small group of annual conferences that explicitly address energy-water nexus research and the topics included in this research. Interviews and group discussions were informal, and gave the participants a chance to identify the aspects of energy and water regulations that most concern them in light of increasing global temperatures and energy demands. No amount of reading or deductive reasoning can replace the sort of insight that seasoned energy, water, and environmental professionals have brought to this research.

Thermoelectric Energy Production

The basic principles of traditional (i.e., Rankine cycle, steam cycle) thermoelectric energy production are fairly straightforward. First, a fuel (e.g. coal, oil, natural gas) is combusted in a boiler to create steam. In the case of nuclear power plants, heat created during the fission of uranium 235 atoms provides the necessary heat. The steam enters a turbine, creating a pressure differential that spins the turbine. The turbine is attached to a generator. Within the generator, wire coils spin at high speed in the presence of powerful magnets to create electricity. Once the steam leaves the turbine, it enters a condenser, wherein it is cooled, either by non-contact cooling water or by air. Once it is condensed, the coolant returns to the boiler to begin the cycle anew.

In a combined cycle system, about two-thirds of the power is generated in a turbine that directly combusts natural gas or a petroleum derivative (e.g., diesel). The gas turbine component requires no water for steam and operates like a jet engine of an airplane. The waste heat is directed from the gas turbine to the boiler of a traditional steam cycle unit. Additional fuel may be used in the steam cycle component to produce steam. The steam cycle component has the same cooling needs of other energy production units, but, overall, combined cycle systems are highly efficient in terms of their thermal and water inputs.

A few of the most common efficiency measures used by industry analysts are thermodynamic efficiency, technical or operational efficiency, and water use efficiency. Thermodynamic efficiency gives an indicator of how well heat energy is being translated to electrical energy. It is expressed as a percentage, comparing the amount of electrical energy generated to the amount of thermal energy produced at a plant (Yang and Dziegielewski, 2007):

$$\mu_{TE} = \frac{360{,}000E}{H}$$

Equation 1. General thermal efficiency equation (Yang and Dziegielewski, 2007).

μ_{TE} is mean thermodynamic efficiency, E is the annual electricity generation (kilowatt·hours, kWh), and H is the annual supplied heat (kilojoules, kJ). The equation may be altered to compare annual electricity generation to supplied heat in British Thermal Units (BTU) by using a different coefficient. Thermodynamic efficiency does not vary substantially from day to day for an individual power plant, but it can vary slightly depending upon plant age, fuel type, technology in use, operator experience, and, to some extent, ambient air temperatures. It can vary greatly from plant to plant. For instance, a steam cycle coal plant is almost always less thermodynamically efficient than a combined cycle natural gas plant.

Technical or operational efficiency, also called capacity factor, is a percentage that compares the amount of electricity produced to the amount of electricity that could theoretically have been produced. Technical generation is the net amount of electricity that a power plant produces divided by the amount of electricity it would produce if it were continuously operating at its nameplate capacity (i.e., 100 percent) (Yang and Dziegielewski, 2007):

$$\mu_{OE} = \frac{100E}{C(24\times365)}$$

Equation 2. General operational efficiency and capacity factor equation (Yang and Dziegielewski, 2007).

μ_{OE} is mean operational efficiency, E is again the annual electricity generation in kWh and C is the generation capacity of the plant. No power plants operate 24 hours per day, 7 days per week, 365 days per year, and some operate with much less regularity than others. For instance, a "peaking" plant will operate only during times of peak electricity demand, whereas "base load" plants operate nearly all the time.

Water use efficiency, which is also referred to as water use factor or water use intensity, describes the amount of water a plant requires to produce a specific amount of electricity. Yang and Dziegielewski (2007) measure water use for 1 kWh of electrical energy and present it as “unit” or “unitary” thermoelectric water use. Regardless of phraseology, it is generally expressed in gallons per kWh. Macknick et al. (2011) offer a review of the most up-to-date water use factors for a variety of power plant types. “Use” may refer to withdrawal or consumption. “Withdrawal” is any removal of water from a surface water or groundwater source. “Consumption” refers to the component of the withdrawal that is not returned to its source and is completely removed from the water resource from which it was acquired (Sovacool, 2009). Efficiencies of water withdrawal and water consumption are highly variable even among thermoelectric facilities of similar age and technology type, and they may vary based on environmental conditions (e.g. ambient air temperatures) and technical efficiency (Macknick et al., 2011).

Theoretically, the water required for a particular steam cycle system is dictated by the amount of heat that is removed during the condensation of steam. Greater fuel inputs or higher combustion temperatures require greater water withdrawals or greater discharge temperatures to condense steam and to carry away waste heat (Yang and Dziegielewski, 2007). In reality, water needs and discharge temperatures can be difficult to predict, due to the complexity of each facility’s generator system and associated data collection. For instance, in the Energy Information Administration’s (EIA) Form-767 database, net electrical energy production values are recorded at the generator level, fuel combustion figures are given at the boiler level and water withdrawal and/or consumption values are recorded at the cooling system level. Strict energy and water resource accounting is made difficult by the fact that condensers, boilers, and generators are often interconnected to a dizzying degree. A single generator may rely upon multiple boilers and cooling systems. One cooling system may service multiple turbines (Yang and Dziegielewski, 2007). Similarly, individual effluent outfalls may serve several cooling systems, auxiliary equipment systems, and even storm water flows.

Still, it is useful to make some generalizations about water use by power plants, and particularly their cooling systems. "Wet" cooling systems use water as the primary transporter of waste heat. Wet cooling systems are further subdivided into "once-through" (open-loop) systems, and recirculating (closed-loop) systems.

Once-through power plants comprise about 31 percent of the total current electricity generation capacity in the U.S. (Hightower et al., 2006), and most are part of power plants that were built prior to the 1980's. In a once-through system, water is continuously withdrawn and discharged. Nearly all of the water withdrawn is returned to its source, but at a lower quality. Environmental practitioners refer to the degradation that occurs between the cooling water intake and discharge points as "heating and treating," because the temperature of the water always increases and it is typically treated with chemicals in order to preserve the integrity of the plant cooling system (Sovacool and Sovacool, 2009a). Some once-through systems include an intermediate step, a cooling pond, where heated water is allowed to cool by evaporation and radiation before it is discharged back into a nearby water body.

A recirculating cooling system withdraws a fraction of the amount of water that a once-through system servicing a similarly sized generator would withdraw, generally 0.1 to 0.01 times the amount. The drawback is that they consume at least two times the amount of water that the once-through systems consume. This trade-off between high withdrawal and high consumption systems may have significant implications for regional energy and water policymakers (Macknick et al., 2011). Recirculating systems use cooling towers in lieu of the assimilative capacities of natural water bodies to dispel waste heat. The cooling towers, which take a variety of forms, including natural draft, induced draft, and forced draft, expose the heated water to air. The heat is carried away as water vapor and steam in the familiar billowing clouds that cooling towers produce.

Both once-through and recirculating cooling systems can use water that ranges in salinity from fresh to open ocean water. Most water withdrawals by thermoelectric power plants are fresh (71 percent). Not surprisingly, most power plants that use saline water sources are located along the coasts. Many are in Florida, California, and the Northeast (Macknick et al., 2011), although brackish groundwater may be an option for power plant cooling in the U.S. interior.

Wet cooling systems also require water for plant cleaning to maintain plant efficiency. Over time, boiler and cooling tower water become degraded with salts and other dissolved solids, and the systems must be flushed with clean water. The degraded water is called "blowdown," and it is discharged into a nearby body of water or into an evaporation pond (Sovacool and Sovacool, 2009a).

As the name implies, “dry” cooling systems use air-cooled condensers and have only negligible water requirements. Many combined cycle systems use air cooling. As yet, dry cooling systems are not a cure-all for U.S. electricity and water demands. At roughly four times the price of similarly sized recirculating systems, they are expensive to install (Yang and Dziegielewski, 2007). They also perform poorly in hot weather and may not be sufficiently scalable for large electricity generation ventures (Hightower et al., 2006).

Environmental impacts

As energy demand for air-conditioning and refrigeration peaks during summer months, cooling water withdrawal rates and discharge temperatures reach their maximum. High temperature, high volume discharges, which have the greatest associated heat rejection, occur when the thermal load of surface waters is already considerably high (Reiley, 1992). Extreme water temperatures and sudden changes in water temperatures can cause fish kills, increased rates of bacteriological and parasitic infection in aquatic organisms, reductions in population sizes, and lowered species diversity. High temperature effluents may also impair the benthic grasses and fauna of estuarine and marine areas. Thermal plumes decrease spawning area and, in some cases, completely block fish passage. Some plumes are so hot that fish eggs, larvae, and plankton are destroyed in them (Reiley, 1992). During winter months, fish often congregate within effluent-warmed stream areas, which are a favorite spot for some fisherman. Unfortunately, thermal shock may occur in such areas if energy generation is suddenly halted (Reiley, 1992).

In a few documented cases, thermal pollution from once-through facilities has changed the chemical composition of the downstream environment enough to induce eutrophication. Eutrophication is characterized by a rapid increase in nutrients that eventually leads to widespread algae decomposition and anoxic conditions (Sovacool and Sovacool, 2009). A documented, but poorly understood effect of increased river temperatures is increased evaporation. Some researchers estimate the associated consumptive losses to be "on the order of, but less than those of recirculating systems" (Shuster, 2009, p. 22).

Scientific opinions vary with regard to the selection of criteria for identifying thermal dangers. In some cases, the gross temperature of the effluent is the parameter of interest. In other cases, the temperature rise between the intake and the discharge point, ΔT, is of concern. A study by Poornima et al. (2006), for example, argues that the attention to ΔT with regard to impaired primary productivity may be misplaced, based on their observation that "acute exposure to temperatures below [104 °F] seem to be well tolerated by [phytoplanktonic] organisms," but that acute exposure to certain biocides, such as chlorine, are very poorly tolerated (Poornima et al., 2006, p. 563). They go on to concede that more data need to be collected and analyzed on the effects of acute thermal and chlorine exposure on primary productivity. It is worth noting that their study limited itself to thermal and chemical effects on phytoplankton (i.e., not fish larvae). One important conclusion of the study is that the addition of biocides and anti-scaling agents to cooling water, which are used to reduce chemical biological fouling, is yet another factor contributing to aquatic habitat degradation at power plants.

The high withdrawals also lead to increased instances of impingement at intake screens and entrainment of phytoplankton and fish larvae within cooling systems (Barnthouse, 2000). An organism is “impinged” when it is trapped by suction and killed at an intake screen. The most common animals to be impinged are fish, larvae, and riparian organisms, although a few isolated incidences have involved the impingement of larger organisms, including the following animals: seals, manatees, sea lions, crocodiles, and sea turtles. If an organism escapes impingement by being small enough to pass into the cooling system, it is “entrained” by being chemically, thermally, or physically destroyed (Sovacool and Sovacool, 2009). Chronic impingement and entrainment of fish stocks can have significant impacts on commercial fish stocks, especially where large scale facilities are adjacent to highly productive estuarine areas. In one study, three thermoelectric plants were responsible for a 10-20 percent decrease in populations in each fish year class, which represented a stress factor that would become more detrimental if occurring in conjunction with increasing commercial fishing activity (Barnthouse, 2000). Baum (2003) estimated annual losses of recreational and commercial quality fish stocks near one large thermoelectric facility in Florida to be on the order of 23 tons, and there is reason to believe such losses may be occurring elsewhere.

Water use rates can be so great and so highly regulated that they change the streamflow regime of their water source. A streamflow regime is the pattern of flow quantity and periodicity, and it dictates the health and biodiversity of a stream’s ecosystem (Poff et al., 1997). These patterns of water levels and flows can vary on a daily, weekly, and seasonal basis (Sovacool and Sovacool, 2009a). In some cases, the flow alteration may become so extreme that natural species populations can no longer survive (Brandt, 2010). In one extreme example, streamflow alteration was so great during times of high cooling water flow that scouring occurred along the banks of the creek into which the power plant discharged its thermal effluent.

While once-through systems may pose the greatest threat to stream biota due to thermal shock and withdrawal-related destruction (Reiley, 1992), the impacts, especially for phytoplankton and potentially higher trophic levels, may be short-lived (Poornima, 2006). In other words, much of the damage done to river ecosystems and the associated cultural, aesthetic, and economic impacts may be reversible.

Climate change risks

There are many global climate change models available for use by environmental scientists today, including the National Center for Atmospheric Research Parallel Climate Model (PCM), the NOAA Geophysical Fluid Dynamics Laboratory (GFDL) CM2.1 model, the United Kingdom Meteorological Office Hadley Centre Climate Model version 3 (HadCM3), among others (Frumhoff et al., 2007). Such atmosphere-ocean general circulation models (AOGCM) are dynamic, and offer insight into the drivers of climate change as well as the degree to which anthropogenic forces may impact global air temperatures and hydrological patterns over the coming century.

An increase in ambient air temperatures will substantially impact future human livelihood and ecosystems. New England will experience earlier snowmelts, more extreme streamflow during summer months due to heavier rainfall, greater evaporatranspiration rates, as well as more frequent and lasting droughts (Betts, 2011). New England summers will include more days where temperatures hover above 90°F. While increased temperatures will mean a longer growing season, there will be greater uncertainty regarding the availability of water supplies for irrigation and other essential uses. For instance, more winter precipitation will take the form of rain rather than snow, effectively decreasing region-wide storage of water as snowpack during low demand months. Coastal areas—including many which host thermoelectric power plants—will be increasingly vulnerable to flooding and stronger storms associated with the increase in atmospheric energy availability.

Changes in local ecology are also expected. Warm-weather pest species will be more persistent, while cold-water fish and wildlife will face greater threats, due to thermal water barriers, decreased dissolved oxygen availability, warmer average water temperatures, and eutrophication events. Hemlock trees, which provide shade to countless New England streams, are expected to decline in number as the warm-weather pest hemlock wooly adelgid (HWA) multiplies. The decline in shade leads to warmer stream temperatures that are not ideal for trout (Moser et al. 2008).

Greater temperatures will be no less risky for people. An increased frequency of heat waves will put stress on at-risk populations, such as children, the elderly, and the sick. Persistent warm weather pests may include disease vectors such as mosquitoes and ticks, increasing the risk of widespread illness (Betts, 2011).

The importance of developing downscaling techniques for global climate models cannot be overstated. At the global scale and for long term climate averages, climate scientists are comfortable professing a high degree of certainty about the direction of ambient air temperatures and possible effects. State and federal resource managers must know where and when climate extremes will occur in order to create actionable policies. Indeed, policymakers and planning agencies are often put in the position of writing legislation and regulations that favor immediate problems of narrow scope instead of addressing long term challenges that—if left unaddressed—may have a colossal and damaging impact.

Using the Hayhoe et al. (2008) data, Cox et al. (2006) investigated the variability of climate change impacts at larger spatial scales (i.e., at the scale of cities rather than the larger climate regions). Their research highlights the spatial heterogeneity of climate change-related social vulnerability within counties, states, and metropolitan regions (Cox et al., 2006). The major driver of their research was the desire to identify the specific communities that are at the greatest risk, thereby providing policymakers with the data they need to make critical decisions and to draw their attention to the people who may need the most help. By offering a solutions-oriented approach, the authors cross the divide between science and policy. For instance, if the intent is to reduce exposure to the negative health impacts of extremely hot days, an urban planning department may institute a tree-planting program to increase shading, or might reform energy or water pricing structures to redirect resources from the areas that can afford them to the areas that need them. While scientists' ability to predict detailed future weather is extremely limited, we can see global trends with increasing spatial and temporal resolution which will strengthen society's ability to plan for seasonal extremes (Betts, 2011).

The impact of climate change most relevant to this body of work is the increase in average summer air temperatures and the frequency of dangerously hot days. As part of their regional climate change impact study, the Union of Concerned Scientists (UCS) devoted a substantial space to discussing the measurable human health impacts of warm weather in the Northeastern U.S. The potential negative health impacts include increasing risks of heat-related illness and death among vulnerable urban populations, worsening air pollution conditions (e.g. ozone), worsening conditions for pollen-based allergy sufferers, and improving conditions for mosquito-borne diseases (Frumhoff et al., 2007). The increasing risks of heat-related illness and death are directly related to utilities' diminished capacity to provide electricity for air-conditioning, but other human health risks arise when black outs and brown outs occurring. Other electricity-dependent public safety systems include traffic lights, street lamps, elevator systems, light rail systems, as well as power tool and heavy machinery operation.

The UCS authors astutely note that tornadoes and hurricanes are generally viewed as the leading causes of weather-related injury and death, but that the reality is different. In fact, from 1993-2003, heat stress-related illness was the leading cause of weather-related death in the United States (Frumhoff et al., 2007). During the five year period 1999-2003, 3,442 heat-related deaths occurred in the U.S. In the absence of air-conditioning and/or sufficient shade during heat waves, the human body first suffers from heat stress, then heat exhaustion, and eventually heatstroke (Frumhoff et al., 2007). The summer of 2006 was particularly hot in the U.S., with urban residents across the nation bearing the brunt of the stress. Between July and August, New York City endured two major heat waves, killing 46 people—mostly the elderly and people with preexisting health conditions. Of the 46 who passed away, only two had functional air-conditioners. The vulnerability of certain populations to heat-related illness and death depends on the air temperature, the degree of exposure, individual bodily sensitivity to heat, and the degree of preparedness (i.e., ability to cope). The wide-spread availability and affordability of air-conditions is a key mechanism for dealing with high temperature days, but is neither a cure-all, nor a simple fix, due to the increased risk of brownouts and blackouts during such days, as we have seen (Frumhoff et al. 2007). Peak electricity demand puts an incredible stress on electricity infrastructure.

Interestingly, the incidences of death related to very hot days are typically lower in southern cities, where populations have adapted to regular periods of extreme heat through the widespread use of air conditioning systems as well as the acclimatization that occurs when an individual lives in a certain place for an extended period of time. Such populations are forced to build hot-weather preparedness into the fabric of their cities in a way that many northern cities have not. Roughly 58 percent of New England homes use some form of air conditioning (e.g. centralized or window unit), compared to 77 percent nationwide (Frumhoff et al., 2007). The knee-jerk reaction by policymakers may be to allow market forces to adjust the level of preparedness. For instance, over time, a greater percentage of the New England population will own air conditioners. Without the right infrastructure planning—specifically the kind of infrastructure that can handle extreme electricity demand peaks—power outages will be more common and natural ecosystems will be forced to bear additional physical burdens.

The UCS authors offer additional recommendations on mechanisms to deal with hot weather days—mechanisms that do not necessarily rely on greater technological efficiency of electricity supply systems—including aggressive home insulation programs, public health education, hot weather warning systems, and greater accessibility to air-conditioned public spaces (Frumhoff et al., 2007). A successful hot weather policy would ensure outreach by volunteers and state officials to at-risk populations (e.g. the elderly, the homeless), would offer 24 hour access to air-conditioned public spaces, and might disallow public utilities to shut off service for non-payment. The load on the electrical infrastructure during such periods of peak energy demand may be reduced with targeted efficiency or effective pricing mechanisms.

The precise metric provided by the NECIA database is maximum monthly air temperature for the entire state of Massachusetts. The NECIA researchers provide maximum monthly air temperature estimates derived from each of the three AOGCMs used (i.e., CM2, HadCM3, and PCM). An average of air temperature values produced by the statistical downscaling performed for each of these models under either A1fi or B1 emissions scenarios is also available. A single air temperature value for each month was derived by averaging the A1fi and B1 scenario values for the all-model average and used in this body of work. While the authors advise against using all-model averages to drive impact models, each of the three model temperature predictions vary little over the two-decade time horizon used here.

There are three possible consequences of using these data as inputs into each of the two maximum thermal discharge temperature models: 1. Temperatures at each of the two power plants are likely to be less variable and somewhat warmer than average temperatures covering the entire state of Massachusetts: Cleary-Flood and Somerset are more southern than most other areas of the Commonwealth and they sit along the coast, where temperatures are greatly influenced by their proximity to the ocean. This may cause the effluent discharge temperature model to produce artificially high or low values which would be more representative of average conditions in Massachusetts rather than the specific conditions in the southeastern part of the state; 2. Maximum monthly air temperatures (i.e., the highest air temperature expected on any given day in a given month) is highly likely to be greater than monthly mean of daily high air temperatures, which was the parameter used to generate the MLR models. This may have the effect of artificially increasing the number of possible dial-back/violation events; 3. The all-model averages are less variable on a month-to-month basis than each of the three models they are based on, which may serve to artificially decrease the number of observed dial-back/violation events (Hayhoe et al., 2008).

NPDES permitting

In 1972, the Federal Water Pollution Control Act (Clean Water Act, CWA) established the National Pollutant Discharge Elimination System (NPDES) in order to minimize the human health impacts and environmental damage associated with large-scale water users (33 U.S.C. 1251-1387). A thermoelectric facility's NPDES permit allows the facility to discharge heated and/or treated effluent into U.S. waterways if the plant operators agree to abide by permit conditions that affect the thermal and chemical properties of the cooling water effluent, and which mandate monthly self reporting. The permit also limits the amount of water that can be withdrawn from the environment in order to maintain natural streamflow regimes. Permit limits continue to be set on a case by case basis, and, as with any other scientific pursuit, the methodology dictates the quality of the results.

Thermoelectric facility permitting under the CWA is largely driven by two rules: §316(a), meant to regulate thermal pollution at the point of discharge, and §316(b), meant to reduce the instances of avoidable fish mortality at the intake point. A tangentially important rule is CWA §303(d), which has implications for thermoelectric facilities that seek to use U.S. waterways. Section 303(d) mandates that individual States must identify bodies of water within their borders that may be identified as impaired according to a federal listing of pollutant and habitat health criteria. It also requires States to publish the listing of impaired water resources. A stream's designation under 303(d), especially in energy or industrial manufacturing corridors, can have the effect of increased scrutiny on all large-scale water users that sit along the stream's banks.

Technically, §316(a) sets maximum discharge temperatures for effluents, while §316(b) sets technological standards. Where published guidelines are absent, NPDES permit writers are authorized under §402(a)(1)(B) to set effluent limitations on a case-by-case basis, using their "best professional judgment" (BPJ) in lieu of federal or state standards (40 CFR §125.3). The best NPDES limitations consider the seasonality of stream conditions (i.e., not just peak summer water temperatures and low flow conditions) in order to use the assimilative capacities of the body of water in order to avoid burdensome costs for the discharger during periods of low biological vulnerability (Boner and Furland, 1982). The worst permits rely upon no predictive models and depend exclusively upon previously established limitations of ambiguous origin.

In 1992, researchers at the U.S. Environmental Protection Agency (EPA) released a report reviewing existing temperature limitation strategies used by environmental regulators throughout the U.S., and they concluded that roughly *one-third* of the power plants which existed at the time had been granted less stringent thermal discharge limitations under CWA §316(a) variance regulations. The same report states that as "a practical matter, EPA has with some permits proceeded directly to developing permit limitations under a Section 316(a) variance if *a set of limitations were determined to be sufficient* to assure protection and propagation of [a balanced, indigenous population]. In such cases, determining the technology-based and water quality-based limitations would serve no practical purpose" (emphasis added) (EPA, 2006, p. 23). The ambiguity and opacity of methodologies established using BPJ to assure "balanced, indigenous populations" (BIP) may have lead to a preference by thermoelectric facility developers to seek variances and might explain the relatively high number of variances issued. The researchers go on to note that the EPA had only limited information on the origins of thermal permit variances that had been granted (Reiley, 1992). The relative inaccessibility of methodologies by federal offices suggests that the permits are primarily managed at the state and local level—a condition that may lead to location-based, but not necessarily scientifically defensible limitations.

With regard to power plants that predate the enactment of the CWA, 40 CFR §125.73 states that "existing dischargers may base their demonstration [of how existing thermal discharges are benign] upon the absence of prior appreciable harm in lieu of predictive studies," which assumes stationarity of climatic and hydrological conditions. For environmental phenomena, stationarity is the condition of being the same through time (e.g. same temperature ranges, same streamflow). It also assumes that a good record of habitat health exists at the site. Milly et al. (2008) demonstrate that stationarity is no longer a suitable assumption, and it is rare to find stream health records for a power plant that are robust enough to definitively verify that no harm as occurred. Where sufficient evidence has been collected, ecosystem-based analyses often reveal that population changes do occur in bodies of water that are subject to stresses by thermoelectric facilities (Reiley, 1992).

The criteria for 316(a) variance *renewal* is even less stringent, being limited to a demonstration that no substantial changes have occurred within the facility systems or with the aquatic biota in question (Reiley, 1992). Still, some cases of permit review stand in stark contrast to the *status quo*-based, largely bureaucratic issuance of many variances and renewals. For instance, upon noticing that a power plant's discharge creek was tidally influenced and clearly served as a natural tributary to a nearby river, EPA staff ordered a review of habitat health. Until that time, facility operators and permit reviewers had regarded the outlet as purely industrial, so no good biological or streamflow records existed. Indeed, it may have even been excavated by the developers as a spillway for cooling water when the facility was constructed in the 1950's.

Nonetheless, the EPA reviewers, recognizing that a stream cannot itself be stressed, but that the ecological communities that it supports can be stressed (Brandt, 2010), selected two reference streams for comparison. For good measure, they sampled fish prior to, during, and following the operation of the offending generator and cooling system. They eventually concluded that no fewer than 10 ecologically important fish and shellfish species experienced stressful and potentially deleterious conditions during the cooling system operation. Not only were the resulting withdrawal and effluent ΔT permit limitations lower, the average withdrawal limitations were seasonally-based (EPA, 2006).

The EPA has a number of designations for a facility that is not in compliance with the limitations set forth by its NPDES permit, and the choice of designation depends on the laws that are relevant to the facility (e.g. CWA or Clean Air Act), as well as the seriousness and frequency of the unauthorized events. Many violations are minor by EPA standards and are corrected by facility managers without the need for action by the government. Serious violations by CWA facilities are marked as "Significant Noncompliance," and, theoretically, followed by informal or formal administrative orders, financial or other penalties, or civil judicial cases filed in a Federal court. The designations are made after site inspections or review of facility self-reports by EPA staff. In the Frequently Asked Questions section of the EPA's Enforcement and Compliance History Online (ECHO) database, the agency is quick to note that violation determinations are made in order to "assist the government in tracking resolution of violations through the enforcement process and do not necessarily represent final adjudication by a judicial or administrative body" (EPA, 2011b). Therefore, the EPA considers its preliminary (and automated) violation markers as "alleged violations," which indicate that thermal, physical, or chemical conditions for some aspect of the power plant may have been exceeded at some moment or for some extended period of time.

In spite of flexible and site-specific temperature and withdrawal limitation procedures, as well as a high frequency of 316(a) variance allowances, alleged NPDES permit violations are common. State and federal agencies have neither the time, nor the resources, nor the predictive capacity to address every violation by issuing warnings or fines. An enhanced permitting strategy would be more standardized and accessible. It might include long-term climate trends and electricity demand forecasts for the service area, rather than relying heavily on existing limitations and unclear limitation-setting procedures. Such an approach might even decrease the rate at which environmental agency representatives and thermoelectric facility managers agree to sign permits that are impossible to abide by or are overly burdensome.

An unintended consequence of NPDES

While the extent to which the NPDES permitting process fulfills the obligations of the federal government and industry is unclear, one conclusion can be reached: by and large, thermoelectric facility managers try to stay within their permitted limits. The commitment to aquatic ecosystem conservation and/or abiding by federal laws has created an unforeseen tradeoff that may have substantial consequences for human and environmental health, which may be reduced to the following motto: derate or violate.

Lakes and rivers are subject to natural hydrological variation from season to season. When power plants rely on surface water for their cooling systems—and most do—they are also subject to seasonal climatic and hydrological variation. Extreme examples of hydrological variation include droughts and floods. Droughts have the effect of reducing fresh water availability for all users over different time scales, and can be severe enough that ecosystems collapse and power plants are forced to seek other water sources or reduce their electricity generation (i.e., derate, dial back). Floods can damage power plant equipment. Meanwhile, frequent and prolonged high air temperature events often have the effect of increasing ambient water temperatures. High ambient temperatures serve to decrease the thermodynamic and water use efficiencies of all types of thermoelectric power plants.

On any given day, when regional electricity consumption begins to increase, independent service operators (ISOs) contact individual power plant managers to request that each plant's electricity generation also increase to meet the growing demand. During droughts and/or heat waves, power plant operators are often put in the position of having to decide to either reduce their energy generation, or violate the specific water withdrawal or thermal limitations outlined by their NPDES permit. The results of a survey of power plant managers by Dziegielewski and Bik (2006) listed NPDES withdrawal limitations as a potential influence on cooling water withdrawal rates. More tellingly, none of the facility operators had ever needed to decrease flows in order to abide by their permit limits (Dziegielewski and Bik, 2006), which may indicate that withdrawal limitations are generally not as difficult as thermal limitations for system operators to handle. Indeed, a study by Stillwell et al. (2009) notes that compliance with thermal effluent limitations by nuclear facility operators during a heat wave in France lead to electricity supply reductions. The brownouts occurred just as residents began to demand more electricity for air conditioning. While dial-back events are usually more of an inconvenience than a human health hazard, they can be life-threatening during times of extreme heat.

The current energy production paradigm is one in which huge quantities of water must be available to power plants all the time in order to ensure reliable electricity provisions. In this way, a certain amount of water must always be reserved for energy production, effectively making it unavailable for other uses, such as drinking, sanitation, and irrigation (Dziegielewski and Bik, 2006). So, from a water security standpoint, continued operation by some power plants, either within or outside of their permit limitations, may run the risk of exacerbating water scarcity (Sovacool and Sovacool, 2009b) and destroying valuable ecosystems.

In the early days of power plant electricity production, the choice of cooling system type was limited only by cost. The need for and availability of locally abundant and replenishable water resources was taken for granted. System variation due to seasonal trends was limited to spikes in electricity demand encountered as a consequence of uncomfortable ambient air temperatures during summer and winter months. With the right amount of fuel stock planning, plant operators could easily avoid power supply constraints. Today, however, the effects of seasonal environmental variation on electricity availability can be profound, as can the effects of power plants on ecosystems. In two recent reports by laboratories of the U.S. Department of Energy (DOE), researchers noted that competition for water resources can constrain the operations of existing power plants and the construction of new power plants (Elcock et al., 2010), and that alternative cooling technologies (i.e., dry, hybrid, adaptive, and water-resource conscious) could enhance energy security (Macknick et al., 2011). The studies conclude by recognizing that electricity supply is vulnerable in many areas, due to uncertainties about future water availability.

It is extremely unlikely that the crafters of the CWA planned to worsen the antagonistic relationship between energy and water regulations, but the fact remains that existing NPDES permitting and permit renewal strategies for many power plants, especially those plants that use once-through cooling systems, are ill equipped to handle the consequences of climatic and hydrological uncertainty and increasing electricity demand. In spite of widespread energy conservation measures in the U.S., the DOE expects total electricity consumption to grow at an annual rate of 1.3 percent per year, reaching 5,149 billion kWh in 2030 (Sovacool and Sovacool, 2009b). In order to meet the ever-increasing energy demands, many older plants will continue to operate. These once-through cooled plants will require permit renewals for the foreseeable future (Reiley, 1992), and given the nationwide prevalence of such systems and their associated risks, the energy and water research community would be remiss if it did not offer alternatives to existing NPDES permitting strategies.

CHAPTER 2

BACKGROUND

Overview

Most environmental models that relate power plants to their environmental context are either extremely narrow in scope, so as to be relevant only to a specific facility or specific species, or are so broad in scope that they are not useful to individual facility operators or environmental regulators. Very few are broad in scope while being relevant to individual facility-environment systems. Even fewer use empirical analysis to examine the effects of potential regulatory actions on facilities' environmental performance. A handful of studies relate to this research directly. Some offer purpose and motivation, while others offer technical insight to the state of the science. The following sections begin with a general review of the most pressing research areas in energy-water nexus research as it relates to energy and water security. From there, the topic narrows to some of the analytical techniques that researchers use to assess the efficiency of water use by thermoelectric facilities. A common tool among researchers in comparing and predicting efficiency (i.e., setting benchmarks for water use) is MLR analysis, but not all studies use it directly. A defense of the selection of explanatory variables which are or could have been correlated with the water use parameters of interest (e.g. withdrawal rate, effluent temperature) is offered using past studies. Next, the regulatory precedent for setting thermal limits under NPDES is discussed, as well as the response of large-scale water users to variations in the stringency of permit limitations and enforcement. Finally, some of the technical limitations of past research are discussed, especially with regard to the paucity and low quality of existing data.

Energy-water nexus research

In 2009, researchers at the National University of Singapore published a series of articles in various law and policy journals addressing the link between electricity and water systems in the U.S., and the associated risks. The articles offer useful insight into the state of research and constructive criticism of the separate paths that energy and water research have taken. The complex challenges of the pursuit to integrate the management of historically separate sectors (i.e., energy and water) are straightforwardly addressed, and the reports are largely free of the equivocations and omissions that many other reports include. Together, the articles offer what might be the most comprehensive, but succinct argument yet conceived for new research directions in the field of energy-water “nexus” research and planning.

An important message in the articles is that if nothing is done (i.e., the *status quo* is maintained), water shortages and environmental degradation will be exacerbated by the ever-increasing water demands of thermoelectric facilities. Where water is no longer available for normal operation, power plant deratings and outright shut downs will become more common (Sovacool and Sovacool, 2009b). Evidence of the persistent disconnection between power plant operators, environmental scientists, and policymakers abounds. For instance, power plants are managed and developed as though they behave predictably in terms of their thermodynamic efficiency, operational efficiency, and water use efficiency, but many older plants experience unplanned outages, while many new plant operators face a learning curve before the plant can reach maximum efficiency (Sovacool and Sovacool, 200b). Water management itself is divided between local, state, and federal agencies, with aspects of it falling within the purview of many different authorities at once (Sovacool and Sovacool, 2009a). As a consequence, any attempts to capitalize on the synergies between improvements in energy and water systems are forestalled by institutional fragmentation. In this regard, ambiguity of authority and inconsistencies between current *modi operendi* leads to failings of the systems that are put in place to protect the environment. Indeed, NPDES violations are fairly common among thermoelectric facilities, and many limits go unenforced (Sovacool and Sovacool, 2009a). It follows logically that, unless power plant operators and environmental regulators *are expecting the violations to occur*, there is room to improve the framework and predictive basis of permitting strategies.

Academic research is in need of new and revolutionary thinking with regard to energy and water system planning as well. Over the last two decades, a bevy of scholarly articles have been published warning that power plant additions that use traditional technology and which abide by long-established permitting schemes may complicate water management efforts (Inhaber, 2004; Anderson and Woosley, 2005; Dziegielewski and Bik, 2006; Yang and Dziegielewski, 2007; Feldman and Garrett, 2008; King and Webber, 2008; NETL, 2009; Elcock, 2010; Roy et al., 2010; Macknick et al., 2011), but very few offer the kind of site-specific and temporal recommendations that would be useful to energy and water planners who work at the ground level (Sovacool and Sovacool, 2009b). Academics are necessarily cautious when using data sets of low spatial and temporal resolution, so the limited utility of their conclusions is not an indictment of their methodologies as much as it is a call for better data. The very organizational structure of the data (e.g. by county, by state) may lead to poor methodological assumptions by the uninitiated. For instance, some studies assume that the electricity consumed by a given county comes from within the county or that a county's rainfall is a good indicator of the water resources available to cities and towns within the county. Both assumptions are very often wrong, but researchers are forced to make the concession in order to draw conclusions about the U.S. as a whole. Even the tendency toward producing generalities about national trends is a detriment when it leads to inaccurate conclusions at the local level.

Sovacool and Sovacool (2009a) point out areas of energy and water research and policymaking in need of improvement and go so far as to build their own geospatial model to compare water resource availability to growing thermoelectric capacity at the level of the Census track—a geographic unit of considerably higher spatial resolution than those in use by most other models. Like previous researchers, however, they are restricted to using disparate data sources, all of different spatial and temporal resolution, which ultimately limits their model's accuracy. For example, they use the EIA-767 Annual Steam-Electric Plant Operation and Design Data set (Sovacool and Sovacool, 2009a), which has a number of documented flaws (Macknick et al., 2011), including possible misreporting and the omission of seasonal trends as a consequence of the yearly time scale used. An important and often overlooked rule in spatial analysis is that when combining multiple data layers, the results are always limited by input of lowest resolution. In other words, when county-specific information is combined with state-level information, accurate conclusions can only be drawn at the state level. Conclusions drawn at the county-level are prone to errors introduced by the generality of the state-level data. The same may be said of temporal resolution.

In any case, the authors' overarching message is hopeful: human beings are able to predict the likelihood of environmental and human crises that may occur over the coming decades. One such crisis that may be avoidable is the increase in energy and associated water demands that would result from steadily increasing air temperatures and more frequent heat waves (Sovacool and Sovacool, 2009a). Resource crunches such as those brought about by inadequate or outmoded energy and water policies may be avoided, quite simply, by better energy and water policies. Most industry reports argue that the answer to growing water needs is better technology (i.e., greater investment in technology research), but high tech solutions are an expensive panacea for what may be a fundamental misunderstanding about the value and best management practices of existing resources (Sovacool, 2009). For instance, electric utilities may begin to avoid the risks inherent in their water needs by mandating energy efficiency measures, by deploying more water-efficient (and existing) technologies such as wind turbines, solar panels, and combined cycle natural gas, and by offering more accurate prices to consumers (Sovacool, 2009). Another possibility, and one that is already employed by a number of power plants in the Western U.S., is the widespread adoption of cooling technologies that use reclaimed and low-quality water sources (Sovacool, 2009).

The use of low-quality water resources for cooling in the Western U.S. is indicative of larger regional trends regarding water valuation. In some parts of the country, such as New England, emissions reductions (e.g. SO_x, NO_x, and CO_2) take precedence over reduction in water use, but the long-term trade-offs between many of the externalities associated with traditional thermoelectric generation are not always clear. Most recently, a great deal of emphasis has been placed on the potentially catastrophic implications of anthropogenically exacerbated climate change (e.g. long term and severe droughts, more powerful hurricanes, widespread flooding, famine, mass migrations, mass extinction), but growing populations and increasing total energy demand all but guarantee that water scarcity is on the horizon, too—with or without any variation of the global climate (Sovacool and Sovacool, 2009b).

Two years after the publication of the Sovacool reports, the National Renewable Technology Lab (NREL) released a report updating, and in most cases verifying, the conclusions reached by earlier, non-governmental researchers (Macknick et al., 2011). The report offers a review of estimates of water withdrawal and consumption factors for the many electricity generating technologies in the U.S., which vary considerably across technology types and even with technologies of the same type. It also discusses the need for improvements in water and energy data collection, and speculates on the negative consequences of failing to address energy-water system inefficiencies.

The NREL researchers, like others before them, mention the impact of environmental variation on the ability of thermal generators to produce electricity. They begin the report by noting that the "power sector is…highly vulnerable to changes in water resources, especially those that may result from potential climate change" (Macknick et al., 2011, p. 1), and go on to point out that substantial increases in the temperature of cooling water sources may result in lowered capacities and shut downs at certain facilities. Specifically, they cite the permit limitation-related shut downs and deratings of power plants in the Southeast during a drought in 2007. Browns Ferry nuclear power plant, for instance, was unable to generate electricity without unlawfully releasing cooling water at extreme temperatures. In some cases, hydrological variation limited the plant's ability to withdraw water because cooling water intakes were exposed when water levels dropped (Macknick et al., 2011).

The authors' clear recognition of the effects of temperature change and the thermal permit implications is encouraging, but like previous reports, environmental variation is categorically excluded from further discussion of the power plant water use factors. The NREL scientists were obviously aware of this omission and point to the inadequacies of the data sources upon which their analysis is based. For instance, inter-annual variations in water withdrawal and consumption intensity were not (i.e., could not be) included in the analysis, due to the fact that most water withdrawal and consumption factors are reported in terms of annual averages. The intensity of water use at various facilities can vary as much as 16 percent as a result of daily and seasonal variations of ambient environmental conditions such as air temperature, wind speed, and level of humidity (Macknick et al., 2011). It doesn't require any significant stretch of imagination to infer that effluent temperatures vary to the same or greater degree as a consequence of daily and seasonal fluctuations. The authors also note with a certain degree of muffled frustration that "[e]stimates of water consumption and withdrawal are displayed irrespective of geographic location, as many published data *do not specify the location or climatic conditions of the plant*" (emphasis added) (Macknick et al., 2011, p. 3). Two of the most commonly cited sources of data are published by the EIA and the National Energy Technology Lab (NETL), but both databases suffer in terms of data quality and completeness.

Identifying explanatory variables with and without MLR

A particularly challenging aspect of investigating the root causes of alleged violations is the difficulty of distinguishing causes from effects and correlation from causation. A working thermoelectric plant is an extremely complicated system, and one could argue that the environmental (e.g. hydrological and climate) systems that support it are even more complex. So, it is not at all surprising to find that there are countless ways in which the systems influence and respond to each other. For instance, an unusually high temperature at an outfall might be marked as an alleged violation by the EPA or state environmental office.

The violation shows up as a tick mark, a data point. But a careful look at the circumstances surrounding the violation leads to a number of questions: Was there, in fact, a violation? Why was there a violation? Was it caused by operator error or did it occur as a consequence of cooling system constraints? If it was caused by actions on the part of the operator, what did he or she do? More specifically, was it possible, in theory, for the operator to have increased the flow rate through the plant in order to lower the temperature of the effluent? Was it possible in reality? Could the operator have derated the plant, thereby lowering the electricity output, in order to decrease the temperature at the outfall? Where, precisely, are the outfall and the temperature gauge located? How were the limitations originally established?

An important thing to realize is that nearly every power plant system is unique, and that plant operators do not have absolute control over every system. What might work to reduce discharge temperatures or withdrawal rates at one facility may not work at another. Only the operators know what is possible at their plant. In spite of the unknowns with which an energy and water regulator must work, a few generalizations are possible. For instance, power plant operators respond to the limitations set forth by permit-related environmental concerns as well as safety concerns. So, where and how can a plant operator act to reduce the number of instances of alleged violations? What should the environmental manager regulate and how? The answers are not always clear-cut.

Theoretically, flow rate through the condenser and temperature rise between the intake and the outfall for once-through systems abide by the following relationship (Backus and Brown, 1975):

$$C = \frac{\Delta T q e}{6823(1-e)}$$

Equation 3. General equation relating cooling water flow rate, temperature rise of cooling water, and thermodynamic efficiency in steam-electric plants (adapted from Backus and Brown, 1975).

where *C* is the capacity in MW, q is the cooling water flow rate in gallons per minute, ΔT is the rise of the cooling water temperature between the intake and the outfall in F°, and e is the thermodynamic efficiency of the facility. A similar equation for the make-up water requirements of recirculating systems is available in Croley et al. (1975). As some scientists are quick to note, however, the actual water requirements of once-through and recirculating cooling systems are likely to be different than their theoretical water needs (Yang and Dziegielewski, 2007). By extension, the temperature rise between the intake and the outfall is also subject to variation, as is the absolute temperature at the outfall. Using the aforementioned EIA-767 database for the years 1996-2000, Yang and Dziegielewski investigated possible causes of water use variation between 3,443 nuclear and fossil-fuel thermoelectric facilities, each with a nameplate of 10 MW or more. At the time of their research, very few studies had addressed causes of the variation.

First, the authors separated the many statistics provided by power plant managers for the EIA survey into four major categories of possible determinants of water use: cooling system type (e.g. once-through, recirculating, cooling pond), fuel type (e.g. uranium, natural gas, coal), operational conditions, and water source (e.g. river, municipal, ocean). They proceeded to use an imaginative MLR approach—one that combines continuous explanatory variables and binary variables to estimate continuous dependent variables—in order to single out the most significant determinants of water use efficiency. As a point of clarification, the authors refer to water use efficiency as "unit thermoelectric water use," which simply means the volume of water used to create a single kWh of electricity. The results of their analysis are summarized in Table 1.

Table 1 shows the potential explanatory variables for determining water use efficiency across plant types, arranged in order of partial R^2 value. Partial R^2 values provide an estimation of variation of the dependent variable that is described by an individual explanatory variable (i.e., the sum of the partial R^2 values is roughly equal to the R^2 value of the entire model). In total, 64 percent of the variation in the dependent variable was explained by the model, and most variables had *p*-values of less than 0.01. Put another way, 36 percent of the variation in unit water withdrawals was left unexplained. The authors did similar analyses for individual cooling system types and found that, apart from the clear influence of cooing system selection on the amount of water that is used, operational conditions, source of water, and fuel types are all important determinants of unit thermoelectric water withdrawals (Yang and Dziegielewski, 2007).

Only two of the explanatory variables in Table 1 vary to any significant degree for an individual generator at a single plant: operational efficiency and summer air temperature (shown in italics). Operational efficiency is a proxy for total generation at the power plant (i.e., the amount of electricity produced in kWh or MWh), with the distinction that as a power plant operates closer to its theoretical capacity (operational efficiency $\approx$ 1.0), water use efficiency *increases*. Conversely, increases in total electricity generation lead to greater total withdrawals, as one might expect. In other words, the power plant uses water more efficiently as it operates closer to its designed capacity, and uses more water when it produces more electricity.

Yang and Dziegielewski (2007) do not explain how they arrived at the figures for average summer air temperature for each plant, or even what the designation specifically means, but one can assume that only one value for average summer air temperature was provided for each plant (i.e., average summer air temperature at each location over many years on record). Such a value would be useless for describing inter-annual and monthly variation at a single plant. What is useful, however, is the implication that air temperature has a measurable effect, even when it is obscured by so much other variation. The implication is that, in the absence of variation in the other variables (e.g. fuel source, water body, cooling system) air temperature would have much stronger explanatory power, and especially for a single plant. The reason for its effect, the authors speculate, is that "air temperature can induce an increase in water body temperature, thus causing a smaller temperature difference between cooling water and steam" and that as a result, "more water would be needed to cool down the same amount of steam" (Yang and Dziegielewski, 2007, p. 166). If the rate of withdrawal were to remain constant at an individual power plant, and in many cases it does, the waste heat present in the steam would be transferred to the non-contact cooling water with the effect that the cooling water's temperature at the outfall would be higher. In any event, neither the change in temperature between the intake and the outfall nor the absolute temperature at the outfall can be regulated directly. They are controlled by the power plant operator's careful consideration of how much energy can be loaded into the stream and by what means (e.g. changing the rate of generation, changing the rate of cooling water flow).

The peer-reviewed article by Yang and Dziegielewski (2007) corroborates much of what appears in an earlier study, based on the same EIA-767 database, by researchers at the same university. Dziegielewski and Bik (2006) sought to establish benchmarks for water use at once-through cooled facilities, based on percentiles of water use efficiency and total yearly withdrawal (in gallons). The benchmarks can be used by environmental regulators and power plant managers to gauge the performance of particular plants in relation to other facilities, based on their water use efficiency. Their model for predicting total annual withdrawals eventually contained 14 statistically significant variables and explained 45.2 percent of the variance in the dependent variable. Two of the explanatory variables were annual electricity generation (MWh) and average summer air temperature (°F). Meanwhile, their model for predicting water withdrawals per unit of generation, a precursor to the model shown in Table 1, contained 6 explanatory variables and explained only 26.1 percent of the variation in the dependent variable. For that model, the explanatory variable with the greatest partial R^2, 0.224, was operation efficiency. In any case, the relationship that the models present is the same: greater energy production, either in absolute terms or as a percentage of theoretical capacity, leads to greater water withdrawal.

Table 1. Linear model of unit thermoelectric withdrawals in all cooling systems (Yang and Dziegielewski, 2007).

Explanatory Variables	Coeff.	Partial R^2
Intercept	296.67*	-
Age of cooling system	0.87*	0.246
Recirculating with forced draft cooling towers	162.30*	0.082
Recirculating with induced draft cooling towers	157.74*	0.098
Recirculating with natural draft cooling towers	150.03*	0.083
Operational efficiency	-1.16*	0.043
Recirculating with cooling ponds or canals	-91.68*	0.033
Mixed recirculating cooling systems	156.59*	0.031
Surface saline water sources	25.24*	0.010
Thermal efficiency	-3.44*	0.005
Petroleum as a fuel	33.86*	0.003
Mixed once through and recirculating cooling systems	-27.67*	0.002
Nuclear fuels	20.01*	0.002
Fresh ground water sources	23.32*	0.001
Average summer air temperature	0.56*	0.001
Public water delivery	-18.14†	0.001
Mean Y = 125.4 dm^3/kWh, N = 3443, R^2 = 0.64, Root MSE = 70.8 dm3/kWh		

* means $p < 0.01$; † means $p < 0.05$. Coeff., coefficient

To a lesser extent, the influence of regional air temperature was also measurable, and positively correlated with total annual water withdrawals. Unlike in the 2007 journal article, the methodology for collecting and incorporating weather data is mentioned, and it is probably safe to assume that the 2007 article was based on the same weather data as the 2006 report. The set of climatological and hydrological data was developed using methodologies that were described by the same research team in 2002 (Dziegielewski et al., 2002). The researchers used state-level average air temperature in °F for the summer months, May through September. There are obvious problems with using such low resolution data of this type, so it is remarkable that their model picked up the influence of the air temperatures at all. Average summer water temperatures may have correlated more strongly with total annual water withdrawals by the facilities, but high quality data of this type are not yet available in any national database. Nonetheless, air temperature was significant for their model (and other MLR-based models), so it is clearly an important factor influencing power plant operation.

The authors show that the greatest predictor of total withdrawals at thermoelectric power plants is annual energy generation, where greater generation typically means greater water withdrawals. Average summer air temperature and system age were also positively correlated with total annual withdrawals, so that plants that were operating in warmer climates generally withdrew more water. With regard to plant age, the authors point to the less efficient designs of older plants as well as the wear that occurs on industrial systems over time to explain high withdrawals. The model that describes water withdrawal per unit of electricity generation uses operational efficiency, maximum temperature rise of water through the cooling system (ΔT), cooling system age, and thermal efficiency as the most important explanatory variables. Their choice of ΔT between the point of intake and discharge for inclusion in the model is somewhat perplexing. It illustrates some of the complications that arise when making a predictive model. That ΔT correlates with unit water withdrawals is not surprising. Indeed, it is expected, given the thermophysical relationship described by Backus and Brown (1975) in Equation 3. But ΔT does not *explain* the rate of withdrawal. In fact, the reverse is true: power plant operators regulate the rate of withdrawal or the rate of fuel combustion in order to change ΔT or to change the absolute temperature of the water at the outfall. The choice of ΔT as an explanatory variable is useful for describing correlation, but it is also an excellent warning about the pitfalls of assumptions concerning causation. For instance, a novice environmental manager who sees the Dziegielewski and Bik (2006) model might assume, *ipso facto*, that ΔT can be regulated directly as a way of indirectly influencing unit water withdrawals, adding confusion to an already complicated process.

In light of their conclusions, Dziegielewski and Bik (2006) offer the same predictions of researchers before and after them: the growing water dependencies and impacts of many thermoelectric systems may lead to "plant shut downs, seasonal restrictions on water pumping, [and] the addition of cooling towers to once-through systems" (Dziegielewski and Bik, 2006, p. II-1)

A study by Elcock et al. (2010) out of the NETL, in an effort to identify coal-fired power plants in the U.S. that are most likely to experience water restrictions in the near future, avoided using MLR altogether. From the outset, the authors recognize that, in many areas, increasing electricity demands on water-intensive generation technology coupled with decreasing fresh water supplies will lead to future supply and demand conflicts. They developed a geographically based model that used a suite of water supply and demand indicators, such as rainfall, changes in electricity demand, population growth, and others (Table 2). Their approach was unique among government reports of its type, because of its focus on individual power plants and its use of plant-specific indicators in conjunction with regional indicators. Each demand and supply indicator was given a rating of either Major, Moderate, or Not Vulnerable. Facilities which had at least two Major demand indicator values and/or at least four Moderate demand indicator values were identified as being vulnerable to demand issues overall. Similarly, facilities which had at least one Major supply indicator value and/or at least two Moderate supply indicator values were identified as being vulnerable to potential supply concerns. Some plants were identified as being vulnerable to both supply and demand concerns.

The specific value ranges for each of the indicator measures is outlined within the report and were somewhat arbitrary when no previous guidance existed (i.e., what constitutes a Major versus Moderate vulnerability could be debated). Regarding temperature as a supply indicator, for instance, facilities that operate in geographic areas that had an average annual temperature of greater than 70 °F were labeled as having Major vulnerability for that indicator, while plants that operate in areas with a 65-70 °F average annual temperature were given a Moderate rating. *Why* the researchers chose those specific temperatures in not clear. Equally arbitrary was the choice of the number of Major or Moderate indicators that would lead to a designation of "vulnerable" overall. In this way, the report is a good example of where governmental decision-making can diverge from scientific inquiry as a matter of practical necessity. Policymakers wanted a list of coal-fired power plants that are most vulnerable to water supply and demand concerns, and they got one. A different methodology might lead to a list of more or fewer vulnerable facilities and might be more accurate, but it would almost certainly begin with the same set of vulnerability indicators. What is so useful about the study, apart from its production of a definitive list of vulnerable plants, is its matter-of-fact identification of the circumstances and trends that can detrimentally impact power supply, water availability, and environmental integrity.

The authors astutely include net electrical generation, air temperature, and streamflow as potentially correlating with thermoelectric power plant vulnerability. High net electrical generation is common for base load power plants. By their reasoning, it would be difficult to replace the base load generation with other sources of power in the event of water-shortage induced dial back. Meanwhile, "[h]igher temperatures are generally associated with reductions in water supply resulting from increased evaporation and uptake by heat-stressed vegetation and to sublimation [of snowpack]" (Elcock et al., 2010, p. 14). Streamflow was selected for the obvious reason that areas with less fresh water generally host power plants that have little recourse in the event of a water shortage, although one might argue that changes in streamflow through time would have been a better measure, and that, in any case, plant operators in water-scarce regions are generally better equipped to handle water restrictions.

Overall, the study may be regarded as a "first blush" look at coal-fired power plant vulnerabilities in light of water supply issues, and the authors were aware of its shortcomings. They note, for instance, "it is likely that several data errors, discrepancies, and misrepresentations remain," (Elcock et al., 2010, p. 50), undoubtedly the result of their use of the EIA-767 Annual Steam-electric Plant Operation database as well as the spatial and temporal generalizations they make. One such generalization is that average trends within large geographic areas are indicative of the trends for the smaller areas contained therein. Elcock et al. concede this point, recognizing that individual locales very often have higher or lower levels of water demand than the averages reported for larger areas. While their argument is provable anecdotally, it was also shown scientifically by Brandt (2010) who writes that the "spatial scale at which a water resource assessment is performed can affect the accuracy and usefulness of the results" (Brandt, 2010, p. 1). One last area for improvement in the NETL study, as the authors note, is the influence of using indicators that may be highly correlated, such as population change per square mile and increasing water consumption by all users. Using highly correlated indicators can give undue weight to particular vulnerabilities, which, in turn, may lead to a misrepresentation of the coal-fired power plants that have the greatest risks.

Their identification of individual power plants for water-related policy changes or technological improvements is a major step in the direction of definitive national action with regard to energy, water, and environmental security, but one is left pondering several points: Do the vulnerabilities outlined by the authors represent reality at each of the plants? When a specific set of detrimental circumstances switches from a potentiality to a live event, how do power plant operators respond and why? How can the undesirable events be avoided? In the near term, should full-scale water emergencies matter as much to regulators and plant operators as water-related deratings and NPDES violations (i.e., events that are not emergencies, but nonetheless detrimental)?

In a unique study by Miller et al. (1992), researchers at the Tennessee Valley Authority (TVA) Engineering Laboratory investigated the impact of incremental changes in meteorology (e.g. air/water temperatures) on thermal compliance and system operations by power plants. Their research had the following goals: (1) identify the environmental variables that control the thermal response of river systems (i.e., ambient water temperature); (2) characterize and measure the response of power plant operations to changes in ambient environmental conditions; and (3) identify the thresholds of response (Miller et al., 1992). Using historical observations of daily water temperature values versus other meteorological observations (e.g. air temperature, humidity, insolation), the researchers first identified the variables which dictated water temperatures at various points within their study area along the Tennessee River. Changes in “dry bulb” air temperature, which is the temperature of a thermometer that is shielded from moisture or radiation, had the greatest impact on water temperatures, and had cascading effects down the river. In other words, the effects of air temperature and solar radiation increases or decreases were amplified—in some cases quadrupled—downstream. Years were grouped on the basis of average annual temperature and streamflow and divided into four categories: Hot-Dry, Cold-Wet, Hot-Wet, and Cold-Dry. Individual years were selected as case studies for each of the four climate conditions. Air temperature appeared to have the greatest impact on stream temperature during the Hot-Dry year and the smallest impact on stream temperature during the Cold-Wet year, with the influence of air temperature falling between the two extremes in the other years and during average conditions. Therefore, the Cold-Wet and Hot-Dry conditions represent environmental extremes. During the Hot-Dry year, every 2 F° increase in air temperature corresponded to a 1 Fº increase in the water temperature in the area of the intake at the Sequoyah Nuclear Plant. In areas upstream of the Sequoyah

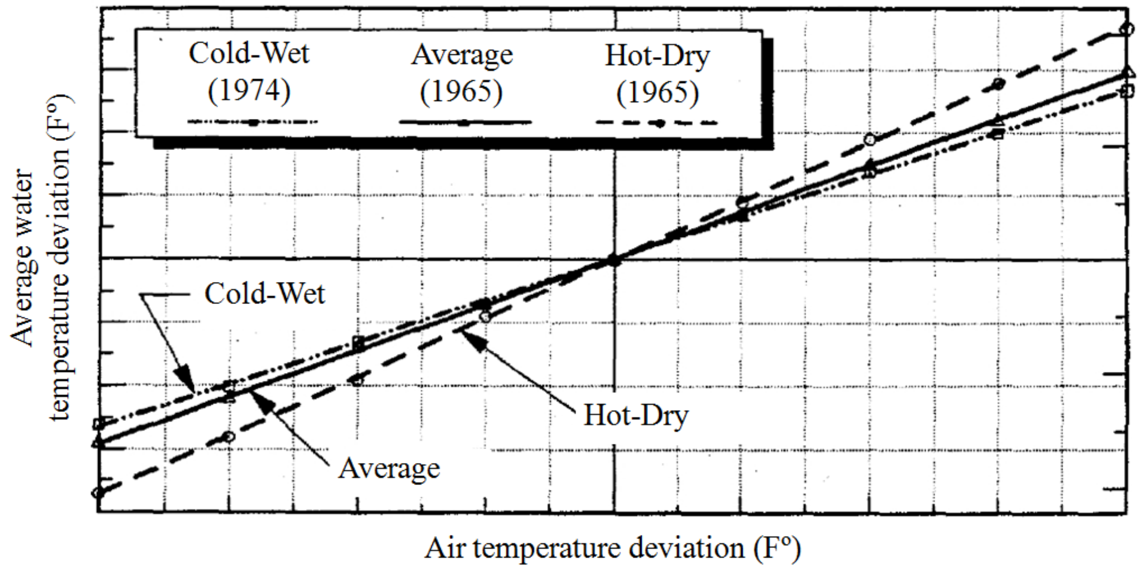
Nuclear Plant, the influence of air temperature on water temperatures was less pronounced.

In their review of power plant operations and based on previous studies, the TVA researchers found that, out of all of the environmental factors that can affect once-through cooled thermoelectric facilities, increases in intake water temperature had the most significant impact. For power plants that used recirculating systems, humidity also had a measurable impact on performance. Using the linear relationship between air and water temperatures under what may be regarded as worst case scenario climate conditions (i.e. Hot-Dry), and utilizing "simplified thermal environmental compliance and safety water intake models," (Miller et al., 1992, p. 16), the researchers estimated the number of days that each power plant would be expected to exceed its thermal discharge limitation or be forced to dial back its generation. The specifics of the "simplified thermal environmental compliance and safety water intake models" are not discussed in any great detail, but it is safe to assume that either instream water temperatures were compared to the thermal effluent limitation directly or that some minimum temperature difference between the points of cooling water intake and discharge had to be maintained to keep the facility running at capacity. In any case, intake water temperatures were used to estimate whether or not plants would be faced with constraints. In the Hot-Dry year of 1986, thermal violations were more common and the number of power plants that faced load reductions increased in conjunction with increased air temperatures. For instance, the Browns Ferry plant suffered a loss of three days worth of electrical generation as a consequence of its cooling water discharge limit of 94 °F., At the time of the next permit review, the limitation was increased, which is illustrative of the fact that regulators will change thermal limitations when the importance of maintaining electrical capacity outweighs that of environmental conservation. Even in the absence of any environmental regulation and/or action on the part of power plant operators, thermoelectric facilities gradually lose generating capacity as a result of cooling water intake temperature increases, as indicated by the downward slope of the line between each point of inflection in Figure 2. In the final section of their paper, Miller et al. include efficiency decreases in their model to estimate the total reduction in electrical energy supply. Overall, they found the severity of air temperature impacts to be highly plant-specific and dependent upon the location of each power plant, the stringency of each plant's environmental permits, and the type of year (e.g. Hot-Dry, Cold-Wet) during which each plant was operating. In most cases during the Hot-Dry years, however, environmental impacts became critical (i.e., introduced generation constraints and/or thermal compliance problems) at air temperature increases 4 F^{o} above the base case.

Table 2. Water supply and demand vulnerability indicators and measures (Elcock et al., 2010).

Demand indicator	Measure
Projected future water consumption - thermoelectric plants	Areas with projected increased consumption by 2030 (% change in water consumption by thermoelectric plants between 2005 and 2030)
Projected future water consumption - all users	Projected high consumption in 2030; projected increased consumption by 2030 (% change in water consumption by all users between 2005 and 2030)
Water withdrawal - all users	Intensity of water withdrawals (gallons per day/mi^2) (by state)
Population	Change in population per square mile (2000 to 2030 by state)
Potential water supply crisis areas by 2025	Areas where existing supplies are not adequate to meet water demands for people, farms, and the environment
Power generation (by plant)	Net annual electrical generation (MWh)
Cooling water consumption (by plant)	Annual average consumption (mgd)
Cooling water consumption intensity (by plant)	Cooling water consumption intensity (gal/MWh)
Cooling water withdrawal (by plant)	Cooling water annual average withdrawal (mgd)
Cooling water withdrawal intensity (by plant)	Cooling water withdrawal intensity (gal/MWh)
CO^2 emissions (by plant)	Tons
Supply indicator	**Measure**
Precipitation	Mean annual precipitation
Temperature	Mean annual temperature
Streamflow	2008 statewide streamflow
Drought	Standardized Precipitation Index
Drought	Palmer Drought Index
Drought	Observed Drought Trends (1958-2007)

Figure 1. Linear model simulating the impact of changes in air temperature on river system water temperature at the Sequoyah Nuclear Plant, adapted from Miller et al. (1992).

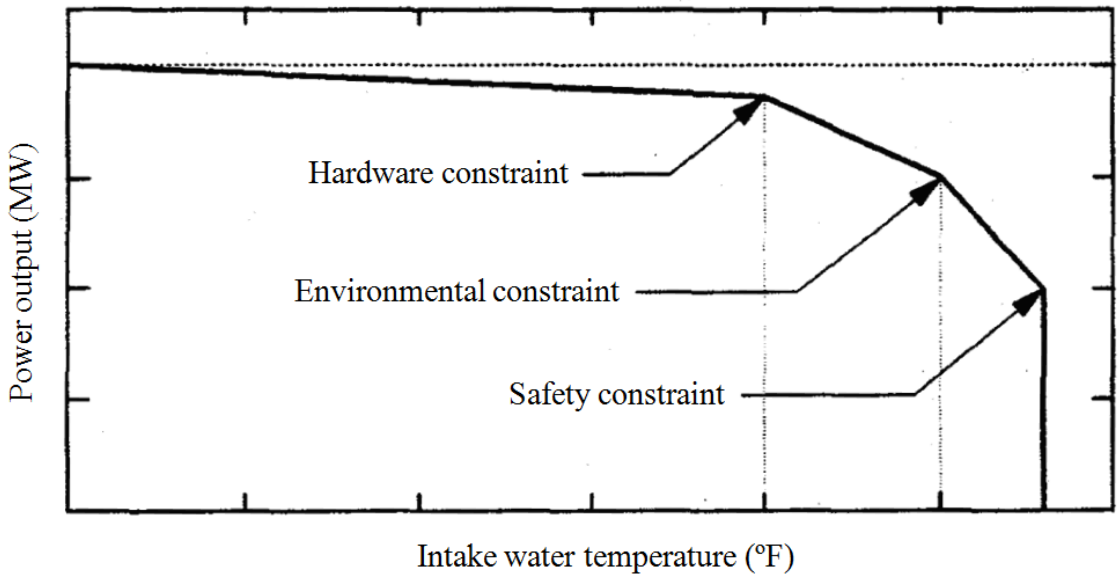


Their 1-dimensional analysis of air and associated stream/intake temperature conditions assumes well-mixed conditions (i.e., no stratification), which may not be representative of reality. In estimating total generation days lost as a consequence of air temperature changes, the researchers assume "full plant operation," which may have the affect of both overestimating the amount of energy that would have been produced on the day of the power plant's dial-back and possibly misrepresenting the total number of days that the power plant would be shut down (i.e., additional down days for maintenance). Furthermore, the various mathematical models that the researchers use are not well described in the text of their report. For all of its limitations, though, Miller et al. (1992) stands out as being one of the very few publically available studies to use plant- and location-specific data of high spatial and temporal resolution. In fact, their data is of higher temporal resolution (i.e., daily time scale) than the data made available through

NPDES permitting itself. The result is that the authors can estimate the number of *days* during which a power plant will be expected to face air temperature-related operational constraints. In many cases, NPDES requires continuous monitoring for certain cooling water parameters, such as water withdrawal rates and effluent temperature, but requires reporting at the *monthly* time scale.

Miller et al. (1992) make it clear that power plant operations are impacted by diurnal environmental variation, so it is unfortunate that federal legislation only requires water withdrawal and effluent temperature observations to be reported on a monthly basis. Given the limitations of current thermoelectric facility reporting mandates, a nationwide study using the methodology outlined by Miller et al. would be impossible. The study also offers a clear, if unusual, presentation of the circumstances at power plants as they appear to facility operators, at the level of individual power plants and at a daily time scale. The authors finish by offering a warning of jarring similarity to those of researchers two decades later: high air and water temperatures can increase the number of incidences where environmental and safety limitations for cooling water are exceeded at thermoelectric power plants, and can cause electricity supply reductions.

Figure 2. Typical effect of changes to intake water temperature on power generation at thermoelectric power plants, adapted from Miller et al. (1992).



Regulatory precedent for limitations under NPDES

Federal guidance for establishing limitations on effluent temperatures at thermoelectric facilities is extremely limited. Most of the guidance for NPDES permit writers, where such guidance exists, comes from state-level environmental quality offices. In a study initiated by the EPA in 1989 and published three years later, scientists compiled state water quality standards (WQS) and reviewed NPDES permit issuance procedures in order to understand CWA §316(a) thermal regulations more fully and to evaluate the efficacy of those regulations in protecting environmental health. Of particular interest to the researchers were the procedures used by permit writers and environmental regulators to establish 316(a) variances.

The results of their review were generally positive. Of the temperature limitation methodologies that were available to the EPA researchers—and many were not available—most were supported by scientifically defensible thermal models that considered waterway size, thermal effluent discharge volume, bank configuration of the receiving waterway, mixing velocities, dilution ratios, and various other hydrological or physical characteristics of the receiving waters (Reiley, 1992). Many NPDES permit writers relied upon the same generalized heat rejection equation when calculating allowable limits:

$$T_d = \left(\frac{Q_1}{Q_d}\right)(T_2 - T_1) + T_1$$

Equation 4. General heat rejection equation for use by NPDES permit writers (Reiley, 1992).

T_d is the maximum allowable or actual discharge temperature, Q_1 is the theoretical river flow, Q_d is the discharge flow, T_2 is the maximum allowable river temperature, and T_1 is the intake temperature. Generally, the theoretical river flow is based on low-flow conditions (e.g. $7Q_{10}$ flow) and median ambient river temperatures.

In order to avoid biological thermal shock caused by heat that is dissipated too quickly within too small an area, power plant operators were required to use, where appropriate, controlled system shutdowns, cooling towers, cooling ponds, fish barriers, diffusers, and submerged pipes. One power plant even had a "Fish Comfort System" installed that "allows the drop of discharge temperature to occur slowly—no more than 10 F° per hour" (Reiley, 1992, p. ES-2). Power plant shut downs were not solely a condition of emergency measures, either. Controlled system shut downs were a relatively common occurrence at the facilities they studied, being used when power needs decreased or when maintenance was necessary. The EPA researchers found operators to be well aware of their power plants' environmental limitations. For most facilities, ecosystem impacts of thermal effluents were believed to be small, and in the few cases where substantial degradation had been occurring, the impacts were caused by administrative errors on the part of the permitting agency when setting the limits rather than by intentional non-compliance.

Certain aspects of their review were less rosy, and a few points underscored certain methodological inconsistencies, and what may be systemic informational gaps. The first point, which the author noted with concern on the first page of the report, was that section "316(a) variance guidelines have never been finalized by the EPA," so there are no universally available methodologies for setting thermal limitations (Reiley, 1992, p. ES-1). While one might argue that a lack of federal guidance ensures that state and local environmental regulators will set guidelines based on local conditions and local expertise, one might also argue that many of the methodologies in widespread use are actually free from the scrutiny of most environmental scientists. In other words, some practices may be common, but may suffer from the biases of local reviewers. One example is that, in some states (i.e., in states with lax environmental laws), power plants are grandfathered into CWA 316(a) variances, without having to make a single demonstration. Similarly, where technology-based effluent limitation guidelines are not available from the EPA, permit writers are authorized by the CWA to use their *best* *professional judgment*. Obviously, BPJ can vary greatly between permit writers and from state to state. A permit writer in one area, as well as the state and federal staff who review the permit, may agree that heat load, which is a function of discharge temperature and mixing area, is the most appropriate measure to regulate, and may wholly disregard absolute discharge temperature. Regulators in other areas may see instantaneous maximum discharge temperature as the most important parameter, and not heat load, for no other reason than historical precedence. There was also clear disagreement between state environmental staff and power plant operators on what constituted "significant environmental damage." Most of the facilities contacted for the study did not report any such damage, but a close look at the ECHO database by EPA researchers revealed that at-plant thermal problems did exist. The discrepancy is indicative of the biases introduced by self-reporting by thermoelectric facility staff. Chronic effects of high effluent temperatures on aquatic species, for instance, would rarely be apparent to power plant operators, but one time fish kills or bank scouring would be. Chronic effects can be serious, and may include reduced biodiversity, changes in the species present, and ill health (Reiley, 1992).

While permit issuance, reissuance, and variance procedures may involve the collection of a whole host of power plant operational data, environmental and biological data, and may also include math-based modeling, it is not always clear that they do. It would be unwise to assume that the studies which took place or are taking place at the most heavily scrutinized facilities are representative of permit procedures as a whole, and especially so in light of the fact that, during permit reissuance, including permits that include variances, the amount of facility operational or environmental data required is characteristically less than that at original issuance. In order to get a permit reissuance—even where original limitation procedures are murky or where it is impossible to prove whether environmental harm has or has not occurred—facilities must only demonstrate that no significant changes have occurred in the facilities operating conditions, the way in which the discharge enters or otherwise interacts with the receiving water, or in the ecology of the receiving waters. That is, the current system gives a substantial priority to maintaining the *status quo*, regardless of whether the *status quo* is the best option. The authors close by noting that the lack of final effluent limitation guidance on the part of the EPA has lead to methodological inconsistencies, and that the EPA has, over time, lost institutional knowledge regarding thermal issues, thereby decreasing their ability to properly review permits (Reiley, 1992).

If permitting procedures were changed and withdrawal and effluent temperature guidelines with them, how might power plant managers respond? In an empirical analysis of NPDES permitted wastewater discharges by large municipal wastewater treatment facilities in Kansas, Earnhart (2007) investigates permittee response. While the study looks only at the years 1990-1998, and while it investigates wastewater treatment facilities and their chemical effluents rather than thermoelectric facilities and their thermal effluents, it offers several lessons that may be true for the group behavior of all NPDES permit holders. More importantly, he bases much of his analysis on information gathered using the EPA ECHO database, and specifically the Permit Compliance System section of the database. ECHO is a resource of information that is generally underutilized by researchers of thermoelectric facility water use, who instead opt for the more general and easier to use EIA-767 and other EIA databases. In accordance with the CWA, NPDES permitted facilities are obligated to provide monthly reports to state and federal environmental offices. The reports, called Discharge Monitoring Reports (DMR), are not always accurate—an expected consequence of self-monitoring—but they are generally regarded as the most important source of information used by environmental regulators to assess facility performance under the CWA (EPA, 1990). Earnhart also consulted with state governmental officials from the Kansas Department of Health and Environment to identify the parameters for which non-compliance garners the attention of environmental enforcement offices.

Earnhart explicitly assumed that environmental regulators are interested in achieving maximum environmental benefits net of compliance costs, which in a grand planning sense is true. In some cases, the EPA will mandate a particular change, regardless of compliance costs, but in other cases, federal regulators are sensitive to the financial burdens that some measures impose on thermoelectric and other industrial facilities. On these occasions, the net benefit of environmental improvement is so small that it does not outweigh the costs of compliance. In those situations, economic arguments and political pressure are enough to stymie even the most pure-hearted attempts at environmental conservation.

In his analysis, he is quick to note that the EPA's "distinction between compliance and noncompliance is too limited, since it fails to acknowledge the fact that many facilities over-comply with effluent limits," which is economically inefficient (Earnhart, 2007, p. 178). For instance, if a facility must limit its discharge of a certain chemical to 10 milligrams per liter (mg/L), but elects to limit the concentration to only 1 mg/L, it is over-complying with the regulation, and especially if there is no measurable benefit to reducing the concentration any further than the original limitation. Over-compliance can introduce potentially unnecessary costs to the facility. Here he makes an excellent point, but one could argue that the EPA and state-level environmental offices, whether correctly or incorrectly, are more concerned with noncompliance than they are with over-compliance. The value of his argument, with regard to NPDES permit writers and power plant operators, probably has more to do with his emphasis on the niggling details of compliance than anything else (e.g. What constitutes compliance? When is it actually enforced?). Many of these subtleties and temporal considerations are captured in his model, which contains several regressors: one that measures the difference between the actual limit level enforced (or necessary given the constraints of the compliance technology) and the facility's federally-mandated limits, one that indicates the facility's average limit level over the study period, and one that considers the change in a limit from one month to the next, among others. Thermoelectric facility permit limitations rarely change from month to month, but occasionally change from season to season if the permit includes such a clause. It is even rare for permit limitations on withdrawal rates and discharge temperatures to change from permit to permit, and, in many cases, permits are supposed to be issued every 5 years.

With a strict regard for realism, Earnhart's paper considers the events of establishing effluent limitations, monitoring, and enforcement independently of each other and sequentially, in the right order. The same cannot be said for many of the aforementioned governmental reports wherein the order of on-the-ground permit actions are often jumbled or sacrificed due to data source limitations. In the end, he draws several conclusions that are useful to consider when analyzing the NPDES process: (1) marginal compliance costs rise as limits fall, (2) level of treatment is typically discrete rather than continuous as a consequence of treatment technology limitations, and (3) adjustments to treatment can take considerable time to execute (Earnhart, 2007). It would appear that no similar study has been done for thermoelectric plants and their compliance with water use and thermal discharge limitations, so it remains to be seen whether Earnhart's conclusions are directly applicable. What is clear, however, is that certain areas of the NPDES permitting, monitoring, and enforcement process are in need of improvement, and that the informational resources exist to begin identifying problems (e.g. the EPA ECHO database as well as expertise on the part of state and federal environmental officials).

Some technical limitations of past research

Previous studies inform this research in terms of the selection of regressors that may explain thermoelectric cooling water use rates and discharge temperatures, but the quality of their results and conclusions would be improved if the researchers addressed the following issues: for the most part, the studies rely upon low spatial resolution (national) climate and hydrological models that can systematically overlook local water scarcities in regions of the U.S that have, on average, abundant water resources (Brandt, 2009); they often use datasets of low temporal resolution (yearly), which consequentially obscure seasonal trends; and they overwhelmingly use the Energy Information Administration's form EIA-767 "water" survey which lacks uniformity and consistency, being based on self-reporting, and which suffers from low temporal resolution. Furthermore, the emphasis on determining water use factors (i.e., rates of water withdrawal or consumption versus power output) may be misguided in light of the permit-related thermal constraints that power plants are currently facing.

The EIA-767 "water" database has a number of documented flaws, which are faithfully documented by Macknick et al. (2011) of NREL. Within the database, for instance, it is common to find water withdrawal and consumption values that are far below or above the theoretical limits set forth by detailed engineering studies. The database is further plagued by omissions, particularly nuclear facilities and certain natural gas combined cycle (NGCC) power plants. According to the same NREL report, the EIA and USGS are actively trying to remedy these flaws.

Yang and Dziegielewski (2007) note, with a certain degree of exasperation, that their "analysis of consumptive water use has been hampered by the inferior quality of the EIA-767 data on consumptive losses of water" (Yang and Dziegielewski, 2007, p. 167). As often as not, once-through power plants report their withdrawal rates as equal to their rates of discharge, which system leaks and diversions ensure is a physical impossibility, even if one excludes the downstream evaporative losses associated with thermal loading. In many cases, water use rates are based on pump ratings and the number of hours that various pumps have been run, which may explain some of the reporting errors (Dziegielewski and Bik, 2006). Reporting withdrawals based on “pump hours” rather than on measured rates of flow is a common practice, especially for older facilities that lack flow meters, and which may never have been required to install flow meters. The preceding study by Dziegielewski and Bik (2006) notes that an additional error arises from the way in which the EIA-767 reports energy generation: on-site electricity use (i.e. service load) is subtracted from total electricity generation in order to calculate *total net generation*, which is the metric reported. The result is that water use factors may wholly misrepresent the amount of water needed to produce a unit of electrical energy for facilities that have very high service loads. Furthermore, the database provides only a partial operational and environmental narrative for the reported parameters. Even where water use rates, ambient water temperatures, and discharges temperatures are accurate, the EIA-767 provides only yearly averages, which do not accurately portray monthly variation due to changes in air temperature, electrical generation, and other operating conditions.

In a master’s thesis submitted by Brandt (2010), the author reveals a common but rarely articulated problem with generalized spatial models. Specifically, she presents a case study which definitively shows how streamflow indicators applied at small spatial scales (i.e., over large areas) emphasize the conditions of large streams, often with the effect that stress conditions for smaller areas contained therein are obscured (Brandt, 2010). While the primary purpose of the research was to show that, in Massachusetts, spatial scales smaller than USGS 12-digit hydrologic units (HUC-12) are insufficient to produce streamflow-related biological stress indicator maps, the crux of the argument applies to all geographically-based indicators. The problem is one of scale dependence. If the value of a measurable property (e.g. air temperature) varies significantly with a change in the size of the sample area, it is scale dependent. For instance, if one were to investigate the vulnerability of power plants to air temperature changes in Southern California, the results would be influenced by the scale of the air temperature parameter. Would it be right to use average air temperature for the whole state of California? Surely not. Just Southern California? Perhaps, depending on whether or not any significant microclimates exist. And what about time scale? Will a yearly average air temperature provide enough information? In this case, the most appropriate scale to use—the scale that would lead to conclusions of the greatest accuracy—may actually involve collecting air temperature data *at individual power plants* and at the time scale by which power plants operate (e.g. hourly, daily). In a more general sense, conclusions drawn from the comparison and analysis of parameters at different resolutions are limited by the parameter with the lowest spatial (or temporal) resolution. Brandt illustrates this by comparing the magnitude of median August streamflow alteration for various basin sizes. She found that as basin sizes increased (i.e., the spatial scale of individual hydrologic units decreased), the magnitude of apparent alteration decreased, causing information about environmentally stressed headwaters to be washed out by the stronger signal of basin-wide conditions.

The study offers a tremendous amount of insight into a problem that plagues many of the studies which try to pinpoint potential areas of vulnerability. Even the harshest critics of past methodologies can commit the same error. In Sovacool and Sovacool (2009a), for instance, the authors appear to have used indicators of insufficient resolution, which led to the conclusion that Boston, MA, is an “Electricity-Water Crisis Area.” The reality is that, per capita, Boston has some of the lowest water use rates in the country for any metropolitan area in the U.S. In the 1980’s, in light of the possibility of water scarcity in Boston, a water diversion project was proposed that would provide Boston with supplies from the Connecticut River. Environmental concerns eventually led water planners to shelve the diversion project and to focus on decreasing demand rather than increasing water supply. A new water conservation standard of 65 gallons per person per day (residential) was put in place—one of the most stringent standards in the country (V. Rao, personal communication, February 17, 2012). To meet the new goal, the Massachusetts Water Resources Authority (MWRA) started an aggressive water conservation program involving repairing aging pipelines, conducting free water audits at homes and industrial facilities, raising water prices, and increasing public awareness. The program has been so successful that, six years ago in 2005, Boston’s total water use was at a 50 year low. Over the 29 year period between its peak in 1980 and 2009, water use dropped a staggering 43 percent per capita (Postel, 2010). Boston, at least in the foreseeable future, appears to be in very little danger of facing either electricity or water shortages. While most of the metropolitan areas that Sovacool and Sovacool identify as potential crisis areas are probably exactly right (e.g. Los Angeles, Atlanta), the Boston example highlights the inherent risks of using low resolution and/or small scale indicators to draw conclusions about small geographic areas.

Finally, regarding the tendency of recent research to emphasize water use factors, it is noteworthy that thermal effluent limitations and associated deratings are often mentioned as sources of risk—even used as justification for increased study of energy and water interactions—but rarely investigated.

An improved model of the interactions between a thermoelectric power plant and its environment might give higher priority to increasing both temporal and spatial resolution, would employ the most accurate water use and energy generation values available, would provide conclusions of justifiable scope, and would include both water use factors and discharge temperatures as parameters of interest.

CHAPTER 3

METHODOLOGY: PART I

This research builds upon previous studies which relate water use rates to electricity generation and ambient environmental conditions by using data of a higher spatial and temporal resolution and generally higher quality. It also explores two other operationally and ecologically significant parameters, *effluent discharge temperature* and *temperature rise through the condenser*. A framework for predicting water withdrawal rates and discharge temperatures would be of greater value to environmental regulators and permit writers than hyper-specific models of limited scope, overly complex models that rely upon data which are often unavailable, or models which are so generalized as to be irrelevant for individual power plants. For example, theory suggests that ambient water temperature would be the best predictor of effluent temperature, but accurate stream temperature records for individual power plants are harder to come by than air temperatures and are often extremely difficult to estimate. Further, models that offer predictions of future climate conditions generally offer estimates of regional air temperature changes, not river water temperature changes.

Two thermoelectric power plants were chosen as case studies, and 41 years (1970-2010) of hourly and daily field measurements of environmental and plant operational observations from various federal and state sources were combined into a single database. Environmental parameters include stream flow, air temperature, tidal height, and others, while facility information includes monthly electricity generation, water withdrawal rates, and effluent temperatures. Ambient air temperature is used as a proxy for ambient water temperature due to the scarcity of historical water temperature data available at each site.

Using permit limitation parameters as dependent variables, correlation matrices were created in IBM's SPSS statistical analysis program to identify highly correlated explanatory variables and to reduce multicollinearity within the model. In most cases, all but two of the explanatory variables could be eliminated without reducing the predictive power of the model. Mean of daily high air temperature for each month (°F) and total energy generation for each month (megawatt·hours, MWh) were the most significant predictors of water use rates and effluent temperature values. Throughout the remainder of the text, the terms water withdrawal rates, water use rates, and flow through conduit will be used interchangeably.

The following sections present a brief summary of the model and how it may offer an improvement on past studies, a description of the methodology used to select appropriate thermoelectric plants as case studies, descriptions of the two power plants that were chosen, a detailed summary of the various input parameters and their origins, a short narrative of how the original model was refined, a summary of the "hindcasting" methodology, and a statement regarding model limitations.

Model overview

With the exception of Miller et al. (1992), power plant deratings due to potential effluent temperature exceedances are mentioned but not modeled. Most previous models were written for the purposes of identifying future water and energy choke points (i.e., water scarcity hazards), rather than trying to understand the complex relationship between NPDES-related constraints and operations at thermoelectric facilities. Unlike past models, the present model gives equal attention to effluent discharge temperatures and water use rates.

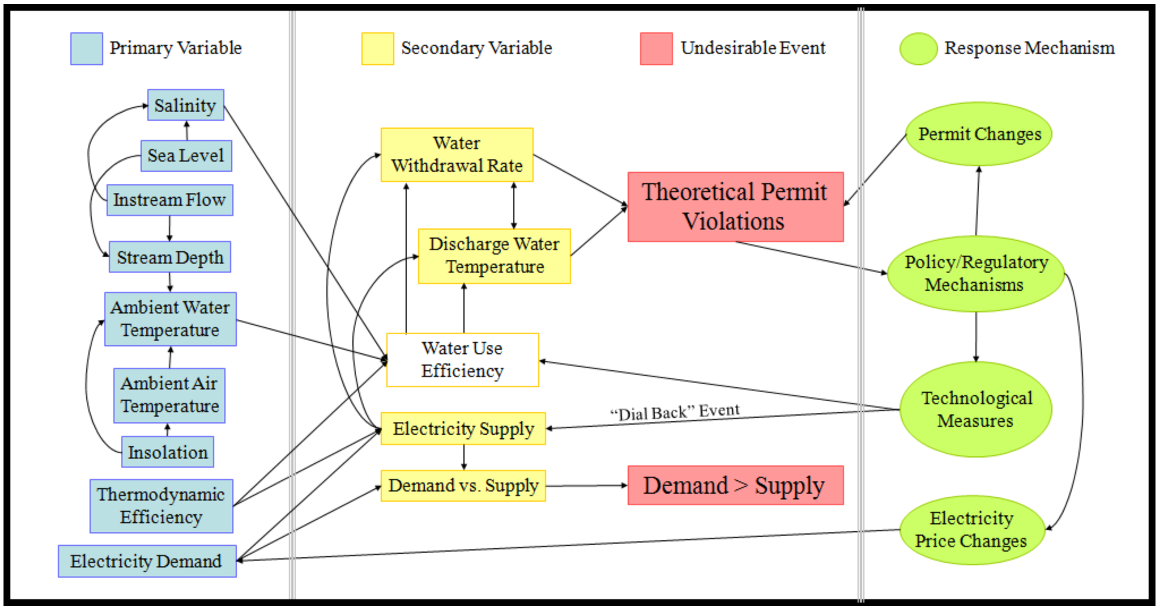
Past studies also focused on inter-facility variation, rather than operational variation occurring at individual facilities. Some of the features of power plants that vary from plant to plant, but not for an individual plant, include cooling system type, power plant age, cooling water source, fuel type, and primary mover type (e.g. steam cycle, gas turbine). For an individual plant, those parameters may be regarded as static. Because they do not vary, they are excluded from the model. Thermodynamic efficiency is also relatively unchanging, and while it was included in the original model, it was omitted from later iterations. The “Primary Variable” section of the preliminary model (Figure 3) shows the many environmental and operational variables that can influence rates of water use and effluent temperatures at power plants. These variables include salinity of cooling water, sea level, instream flow, stream depth, ambient water temperature, ambient air temperature, solar insolation, thermodynamic efficiency, and electricity demand.

Eventually, the Primary Variables were winnowed away and refined, so that they included only the most significant variables that explain water use rates and effluent temperatures. The variables are described in detail in later sections.

The basic theory of the model is simple: measurable environmental phenomena and power plant operations (i.e., electricity generation) dictate rates of water withdrawal and effluent temperatures, and therefore dictate whether facility operators will be faced with the unpleasant decision of dialing back electricity generation or violating NPDES limitations. Furthermore, it is possible to make regulatory changes, shown as “Response Mechanisms,” that reduce the instances of environmental and operational stress. Each of the arrows in Figure 3 represents a mathematical relationship. Many of the relationships are insufficiently described in the academic literature to produce a fully functional theoretical model, especially in light of the fact that some of the relationships are plant-specific. The model evolved to reflect this fact.

A central principle operating in the background of the model is that the quality of the inputs (i.e., observed values) influences the quality of the output. The model is meant to operate at the same time scale and at the same resolution as a NPDES-mandated DMR (i.e., monthly and for an individual plant). Another tenet of the model is parsimony, which states that no more causes or forces should be attributed to an event than are necessary to account for the facts. The preliminary model looks complex, but it was eventually sculpted to include only a few of the Primary Variables.

Figure 3. Preliminary model relating environmental variation and energy generation at power plants to permit violations and deratings.

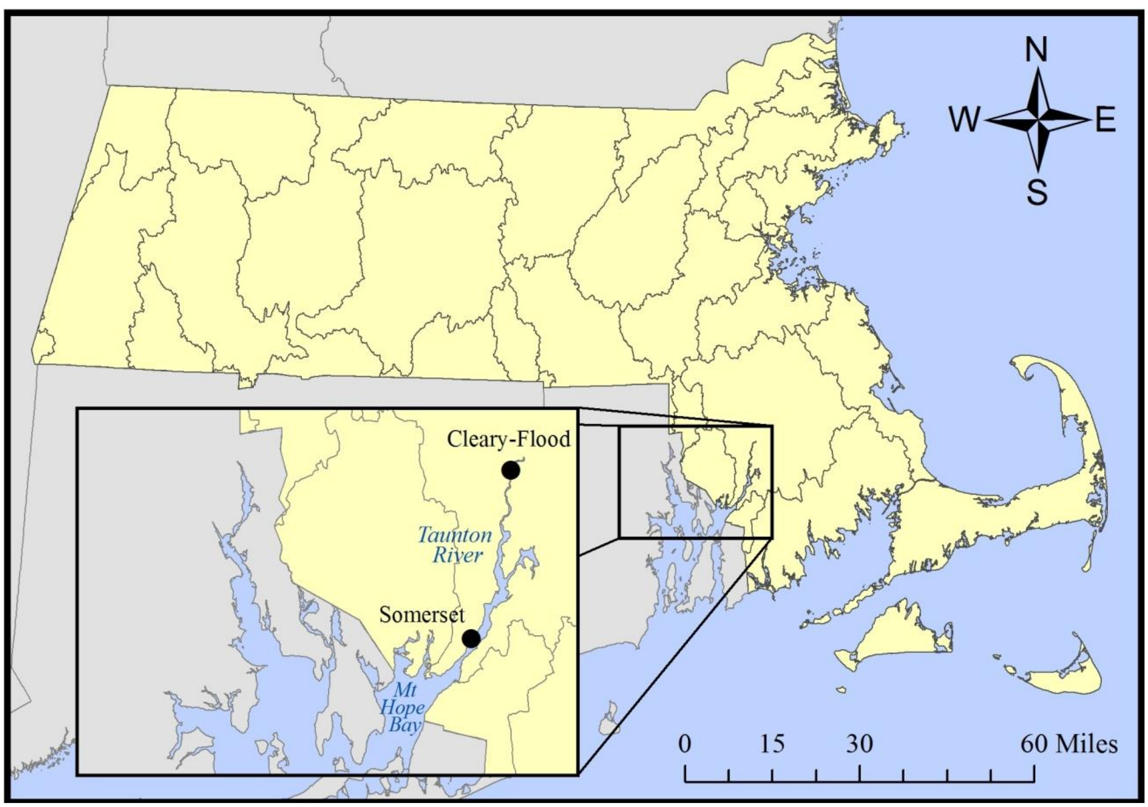


Selection of case studies

Two power plants in Massachusetts were identified as suitable case studies, based upon facility age, primary mover system type, cooling system type, generation capacity, proximity to Clean Water Act §303(d) listed impaired surface waters, and data availability. Facilities older than 40 years are generally less efficient in terms of water use and are prone to thermal pollution. Facilities that use once-through cooling systems withdraw huge quantities of water, and discharge it at high temperatures. They are part of an aging infrastructure that will likely continue operating for at least the next decade. Steam cycle technology is the most common primary mover at thermoelectric plants in the U.S., and such plants generally rely upon water to a greater degree than other types (e.g. NGCC). Plants with nameplate capacities (i.e., theoretical maximum power output) of less than 100 MW were excluded, because most of the electricity generated in the U.S. originates at plants with nameplate capacities above that amount. In order to capture the influence of natural streamflow, the power plants had to use water from an unregulated river—one with no dams and reservoirs. Two thermoelectric power plants met each criterion: Cleary-Flood and Somerset power plants on the Taunton River.

At roughly 43 miles in length, the Taunton River is the longest wholly undammed coastal river in New England. It forms at the confluence of the Town River and Matfield River near Bridgewater, Massachusetts, and terminates at Mount Hope Bay. The Taunton River drainage basin covers large sections of Norfolk, Plymouth, and Bristol counties and has an area of 529 square miles (MassGIS, 2003). The river is exceptionally flat throughout its length, so backwater effects at high tide can be significant, as can low-tide effects. The lower reach of the Taunton is highly urbanized, with power and manufacturing facilities dominating the banks (Cantwell et al., 2007). Unsurprisingly, it was included on the 1998 CWA §303(d) list of impaired waters, primarily for pathogens, put physical habitat destruction has also been an issue. In fact, a 2006 study by GeoSyntec Consultants asserts that 27 percent of the river miles along the Taunton that would otherwise support rich aquatic life were impaired, while 90 percent of the coastal and marine areas of the same type were impaired (GeoSyntec and MassEEA, 2006). The sheer number of reports and action plans for the Taunton River that have been published by state regulators and environmental planners over the last 15 years underscores the importance of preserving this sensitive area (Desbonnet et al. 1992, MassDEP 2001, GeoSyntec and MassEEA, 2006). Action plans Indeed, the river's primary function should be considered biological rather than industrial. Despite its level of impairment, it is listed as a Living Waters Core Habitat by the Natural Heritage and Endangered Species Program (NHESP) within the Massachusetts Division of Fisheries and Wildlife, which means that the Taunton hosts rare aquatic species and has relatively high biodiversity. The estuary at the mouth of the Taunton serves an important ecological function as a fish nursery, and many other areas of the Taunton host variety of aquatic species at various life cycle stages.

Figure 4. Map of Cleary-Flood and Somerset facility locations.



Cleary-Flood

The Cleary-Flood Generation Station (Cleary-Flood) is a natural gas- and distillate fuel oil-fired thermoelectric facility with a nameplate capacity of 135 MW. It is owned by the Taunton Municipal Lighting Plant, a publicly owned electric utility. It has two active units: Unit 8 has a capacity of 28.3 MW, uses a traditional Rankine cycle system (i.e., steam cycle), and employs a once-through cooling system. Unit 9 has a nameplate capacity of 110 MW, uses a combined cycle system and cooling towers. Unit 8 has been operating since 1965, and Unit 9 has been operating since 1975. As a “peaking facility,” the station is used at peak times of electricity demand (EPA and MassDEP, 2006). Cleary-Flood sits approximately 12.5 miles from where the Taunton meets Mount Hope Bay, and its coordinates are 41°51′54″ N, 71°06′21″ W.

In accordance with its NPDES permit, Cleary-Flood withdraws water from the Taunton River, and discharges water into a tidal tributary located nearby. The two outfalls of interest are Outfall 001 and Outfall 002. Outfall 001 is primarily used for discharging Unit 8 non-contact cooling water, but Cleary-Flood is also authorized to discharge auxiliary equipment cooling water during an emergency. Outfall 002 is primarily used for boiler blowdown and boiler blowdown “quench” water, but it also serves as the drain for a number of other effluents: auxiliary equipment cooling water, carbon filter back wash, neutralized demineralizer regeneration wastes, uncontaminated floor drain water, and storm water. Figure 6 shows a simplified model of Cleary-Flood and its connection to the Taunton River. With the passage of the CWA, Cleary-Flood was obligated to obtain a permit in order to continue discharging heated effluent into the Taunton River. The first NPDES permit was issued for Cleary-Flood on August 30, 1978 (EPA, 2006), with permit reissuance theoretically occurring every 5 years. A total of 4 permits were available for review and were signed on the following dates: September 29, 1983; April 19, 1988; September 30, 1994; and September 13, 2006. The existing permit is currently up for review and reissuance.

Figure 5. Satellite image of Cleary-Flood (Google Earth, 2010).

Each NPDES permit requires a monthly report (i.e., a DMR) of water-related observations to be submitted to state (MassDEP) and federal (EPA) agencies. Different parameters must be reported for each outfall. Outfall 001 has limitations and requires reporting of 4 parameters that are of interest to this analysis, and they are *maximum instantaneous effluent temperature* (°F), *maximum instantaneous difference between intake and discharge temperature* (ΔT, in F°), *average withdrawal rate* (reported as million gallons per day, MGD), and *maximum instantaneous withdrawal rate* (mgd). Additionally, the permit limits pollutants such as chlorine, oil and grease, total suspended solids, and sets a range of allowable pH. Meanwhile, the NPDES permit requires the limitation and reporting of 3 parameters of interest at Outfall 002, and they are *maximum instantaneous discharge temperature* (ºF), *maximum instantaneous withdrawal rate* (MGD), and *average withdrawal rate* (MGD). Note that the maximum instantaneous difference between intake and discharge temperatures (ΔT) is not required to be reported for Outfall 002. Chemical pollutants are also subject to limitations for Outfall 002.

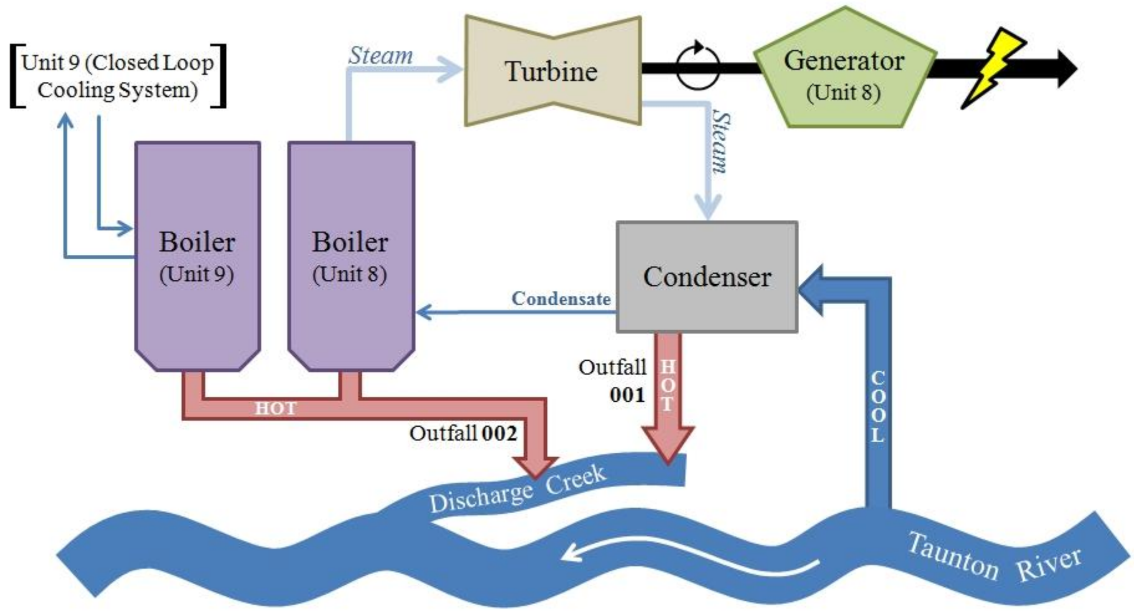
For the purposes of consistency and comparison to natural stream flows, withdrawal rates, also referred to as "flow in conduit" or "flow through condenser," will be reported in units of cubic feet per second (cfs), which is a preferred unit for flow used by stream hydrologists.

No major changes were made to permit conditions between the years 1983-2005 for either outfall. The maximum allowable instantaneous discharge temperature for Outfall 001, was set at 90 ºF, and is still set at that temperature. During that period Outfall 001 had the following conditions: ΔT had to remain below 30 F°, the withdrawal rate could at no time exceed 61.1 cfs, and the average withdrawal rate for the month could not exceed 61.1 cfs. It is unclear why a limitation on the average withdrawal rate was even necessary, since the maximum withdrawal rate was set at the same value (i.e., 61.1), unless, as Earnhart (2007) points out, environmental regulators were more concerned with enforcing average values than maximum values. It is also unclear why the original permit writers and reviewers would have allowed the average and maximum withdrawal values to *exceed* the natural flow of the Taunton River during 7-day, 10-year low flow events (i.e., $7Q_{10}$). During $7Q_{10}$ conditions, the Taunton flows at a rate of only 37.7 cfs (EPA, 2006).

Outfall 002, over the same 23 year period, had an allowable average flow rate limitation of 0.39 cfs and a maximum allowable flow rate of 0.62 cfs. Outfall 002 also had a maximum allowable discharge temperature of 90 ºF and still does.

During a review of Cleary-Flood's permit with regard to the "Discharge Creek" in 2005, the EPA found that the thermal effluent from Outfall 001 was a "significant stressor…and ha[d] the potential to affect portions of the Taunton River" (EPA, 2006, p. 5). Additionally, the EPA found a substantial amount of scouring to be occurring along the banks of the Discharge Creek as a result of high cooling water flows. An earlier study of the Discharge Creek, officially called Unnamed Tributary (Segment MA62-48) by the MassDEP, revealed that the Discharge Creek had originally been a wetland and was either excavated to accommodate the high cooling water flows of Cleary-Flood or formed as a consequence of the flows (MassDEP and MassEEA, 2005). The discharge creek is tidally influenced and consists primarily of Cleary-Flood discharge water during low tide.

Figure 6. Diagram of boilers and once-through cooling system at Cleary-Flood.



Clear biological impairment led the permit writers and reviewers to change several of the parameters for Outfalls 001 and 002, with the exception of maximum instantaneous discharge temperature, which was left unchanged. Beginning in December 2006, Outfall 001 had the following limitations: ΔT could be no more than 23 Fº at any time, the average allowable rate of flow could be no greater than 8.97 during the warmer months (March to November) and no greater than 12.7 cfs during the cold months (December to February), and the maximum cooling water flow rate could be no greater than 55.7 cfs at any time. At Outfall 002, the limitation for average rate of flow was lowered slightly to 0.37 cfs, while the limitation on maximum instantaneous flow was increased to 0.73 cfs. Maximum allowable instantaneous discharge temperature remained at 90 ºF.

Over the past five years, Cleary-Flood has been cited, both formally and informally, on many occasions for temperature and withdrawal rate violations. The EPA ECHO database showed 28 separate alleged temperature violations, and 5 separate alleged withdrawal rate violations for Outfall 002. Two temperature rise (ΔT) violations are shown for Outfall 001. The ECHO database—and apparently no public databases—list the number of days that Cleary-Flood has had to dial back its generation as a result of NPDES permit limits, or the specific dates when maxima occurred.

Somerset

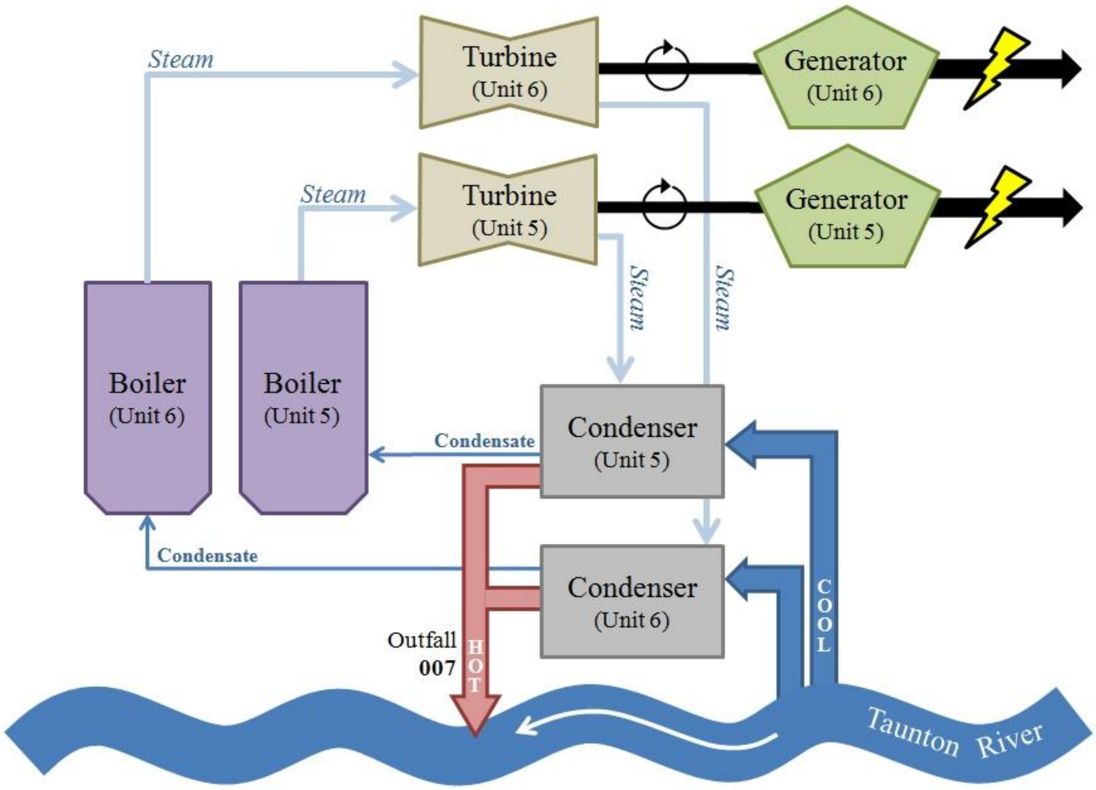
The Somerset power plant (Somerset) is a coal-fired thermoelectric facility with a nameplate capacity of 224 MW (EIA, 2011d), used for base load generation. It is owned by Somerset Power, LLC, whose parent company is NRG Energy, a private entity. Over the period of 1959 to 2009, it had at least one active unit (Unit 6), which was commissioned in 1959, and which used fluid-bed boiler (steam cycle) technology with a 100 MW nameplate capacity. Another reserve unit, Unit 5, also used steam cycle technology and has a nameplate rating of 74 MW, but it was rarely used. Somerset sits along a highly tidally influenced reach of the Taunton River, and roughly 2.8 miles from where the river meets Mount Hope Bay. Its coordinates are 41°44′16″N, 71°08′42″W.

In November of 2009, a spokesperson for NRG Energy announced that the Somerset facility would shut down in January of 2010, but that NRG planned to pursue a legislatively mandated conversion to plasma gasification technology (Dion, 2009). A press release by the Conservation Law Foundation during the same time period sees the retrofit to experimental coal gasification technology—which would change the thermodynamic and water use efficiencies of the plant but not its overall reliance on abundant water supplies—as unlikely (Cleveland, 2009). The facility's temporary closure does not affect the hindcasting portion of this analysis, but it is a factor in the forecasting portion.

The first NPDES permit for Somerset appears to have been signed on May 19, 1980. The permit was reissued on at least three other occasions, with significant changes to withdrawal rate limitations taking effect in the mid-1990's. The original permit was not available for review, but the three permits that were available offered substantive limitation information. The flow and temperature limitations were issued on the following dates: December 15, 1982; August 30, 1989; and September 30, 1994. In accordance with its NPDES permit, Somerset withdrew brackish water from the Taunton River and discharged water just downstream of the intake. The outfall of interest to this research is Outfall 007, which was primarily used for discharging Unit 6 non-contact cooling water. It was also authorized, upon approval by EPA regulators, to discharge the non-contact cooling water of Unit 5. Figure 8 shows a simplified model of Somerset and its connection to the Taunton River.

Figure 7. Satellite image of Somerset (Google Earth, 2010).

Figure 8. Diagram of boilers and once-through cooling system at Somerset.



The *maximum allowable instantaneous discharge temperature* for Outfall 007 was set at 100 °F and the *maximum allowable instantaneous temperature rise through the condenser* (ΔT) was set at 25 F°. Both limitations have not changed over the course of the 30 years that the power plant has been regulated under NPDES (EPA and MassDEP, 1994). The *average withdrawal rate* limitation of 427 cfs was reduced to 220 cfs in the 1994 permit. Likewise, the *maximum instantaneous withdrawal rate* limitation of 579 cfs was reduced to 309 cfs under the 1994 permit rules. Its NPDES permits also set limits on chemical pollutants and other water quality indicators such as residual oxidants, pH, oil sheen, and presence of foam. It has not been cited for any thermal or withdrawal-related violations in the last 5 years, although it is possible that it has violated its permit at other times during its 50 year lifespan, or has been required to dial back its generation in order to meet environmental restrictions. Off-line records were not complete enough to offer any insight into whether or not this was the case.

Introduction to description of data

Although there are no complete data sets for the parameters of interest, there are multi-decadal sets of hourly, daily, and monthly data available that allow for the calculation of most of the explanatory and dependent variables to a certain degree of accuracy, and which allow for statistical analysis. The Massachusetts Department of Environmental Protection (MassDEP) houses the “complete” NPDES permit records for each of the facilities at its Southeast Regional Office in Lakeville, MA. Here, “complete” means all records that appear to exist or are reasonably accessible by the public (i.e., the researcher) and are sufficient for the purposes of the analysis. The limiting factor for both Cleary-Flood and Somerset is the availability of monthly discharge monitoring reports, which list observed effluent temperatures and observed cooling water flow rates.

Several pieces of software were vital to the completion of this research. ArcMap, within ESRI’s ArcView v9.3.1, was used for all flow calculations and most distance calculations, for visualization, and map creation. Google Earth v5.2.1.1588 was used for some distance calculations, visualization, and satellite imaging. Microsoft Office Excel 2007 (v12.0.4518.1014) was used as the primary database for all parameters, observed and calculated, and for hindcasting calculations. IBM's SPSS v19 statistical analysis software program was used for multiple linear regression analysis and for the creation of most graphs.

The following sections describe the nature, quality, scope, and completeness of the various sources of environmental and operational data that were used in model development. Data modifications in preparation for multiple linear regression analysis are also described. Finally, the hindcasting methodology is explained, as are model limitations. Unless otherwise stated, any omissions or errors should be attributed to the author, rather than to the agencies that provided the data.

Data: dependent variables

The EIA-767 provides intake and discharge temperatures for the winter and summer "peak [generation] load" months in degrees Fahrenheit. Summer and winter effluent temperatures are given, but date ranges for the seasons are not. The EIA-767 provides yearly average cooling water withdrawal and consumption rates, and it has been used as the primary data source for a suite of recent water use factor studies. But while the EIA data set may be useful for comparing many power plants to identify the facility features and operating conditions that most influence the plant water use factors, it was unsuitable for a plant level analysis for a variety of reasons: (1) withdrawal and consumption rates are estimated by EIA-767 survey respondents, with no clear guidelines for estimation; (2) withdrawal and consumption figures are given only as yearly averages, which necessarily obscures seasonal variation; (3) withdrawal rates and discharge temperatures vary little on an annual basis for the case studies; (4) the EIA transferred 767 survey components to the EIA-906/923 survey during the year 2006, so data are unavailable for that year.

It is reasonable to assume that power plants do not keep high quality records on site, but representatives of Cleary-Flood and Somerset could not be reached, either by phone or email. Unfortunately, the precedent for cautiousness on the part of power plant personnel to communicate with the public—and especially environmental scientists—is well established. Facility operators have a substantial disincentive to report all of the environmentally relevant values that they measure, and in many cases, the values which power plants are *obliged* to report are scarcely accessible by the public. Even where they exist, observations of a certain type or temporal resolution that are not specifically reported in a DMR as part of NPDES requirements are especially difficult to obtain.

A case in point is the study by Dziegielewski and Bik (2006). As part of their analysis, the researchers surveyed a number of power plant operators. The results of the survey document a widespread unwillingness by power plant managers to provide information to the public. In general, the researchers found obtaining feedback from power plant personnel to be a substantial obstacle to the goals of their study. Among their conclusions were that “there may be some concern that participating in studies about power generation water use only results in efforts to further regulate power generation facilities,” that “[h]ierarchical administrative structures make it difficult for staff to participate in surveys without prior approvals” (Dziegielewski and Bik, 2006, p. IV-4) and that some private facilities consider their operational information to be proprietary.

The best source of publically accessible information for thermoelectric facility operational data is the collection of monthly DMRs (hard copy), available for random years, and the EPA ECHO database, which reports the last 5 years worth of DMR values. With the exception of Earnhart (2007), none of the aforementioned studies used these NPDES observations. Indeed, the EPA echo database is largely underutilized by environmental researchers who study water use by thermoelectric facilities. In the future, it may serve as a preferred source of information for setting water use benchmarks (i.e., water withdrawal and consumption factors) for power plants.

The following table shows the results of a review of the hard copy and online records available for DMRs of both Cleary-Flood and Somerset stations. A file review of MassDEP records provided data for Cleary-Flood for August 1994 to July 1999. The EPA ECHO database provided information for Cleary-Flood from October 2005 to September 2010 (for maximum values), and January 2006 to December 2010 (for average values). The same online database provided data for Somerset October 2005 – December 2009. The actual values reported are shown in the Appendix (

Table A1) and are summarized in other sections.

The NPDES-mandated DMRs provided the average and maximum monthly withdrawal rate as "Flow, in conduit or Thru Treatment Plant" as gross values in million gallons per day (mgd). Again, reported flow values were converted to cubic feet per second (cfs) according to the following relationship:

$$1\ mgd = 1.5472\ cfs$$

Equation 5. Conversion of million gallons per day to cubic feet per second.

Observed absolute effluent temperature values were reported in °F, and changes in temperature (ΔT) were reported in F°. Discharge temperature was, in accordance with permit conditions, measured in the Discharge Creek before entering the Taunton river for Cleary-Flood. Temperature values were measured just before the point of discharge into the Taunton for Somerset. Intake temperatures were recorded, but not reported, and intake temperatures cannot be inferred from reported maximum effluent temperatures and maximum ΔT—an important point that is discussed later.

Maximum effluent temperature

For both power plants and all three outfalls, monthly DMRs provided data on the maximum instantaneous effluent temperature observed. Each NPDES permit states that the limitation cannot be exceeded at any time. The following histograms give an indication of the distribution of observed maximum effluent temperatures at each of the three outfalls.

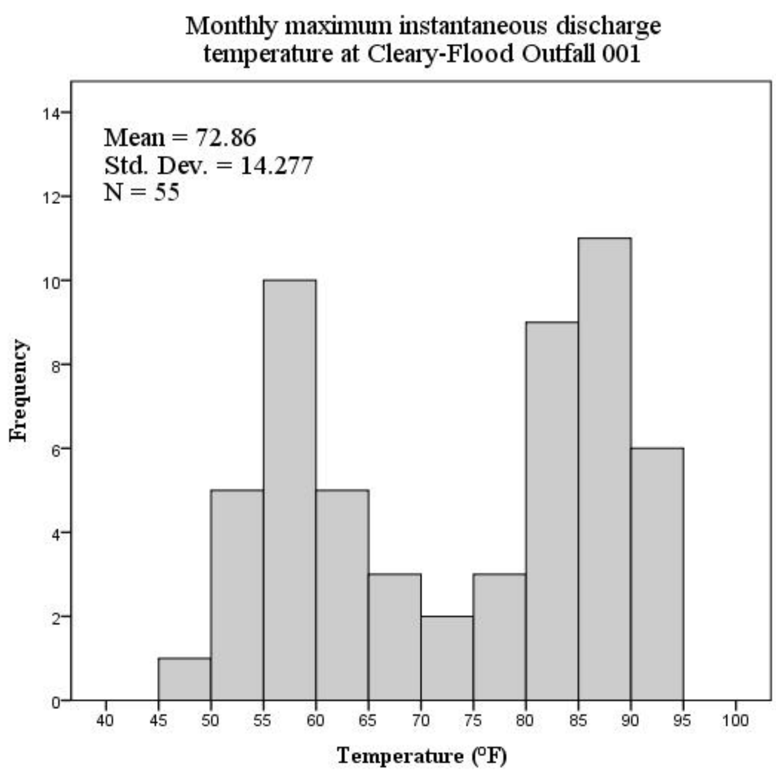
Table 3. Summary of parameters reported for once-through cooling system outfalls at Cleary-Flood and Somerset, date ranges, count, and source.

Plant	Outfall	Dates	Avg. Flow (*n*)	Max. Flow (*n*)	Max. Temp. (*n*)	Max ΔT (*n*)	Source
Cleary-Flood	001	*Aug. 1994 – Jul. 1999*	25	25	25	25	MassDEP SERO
		Oct. 2005 – Dec. 2010	28	30	30	29	EPA ECHO
		Total	53	55	55	54	
	002	*Aug. 1994 – Jul. 1999*	31	31	31	NR	MassDEP SERO
		Oct. 2005 – Dec. 2010	50	50	50	NR	EPA ECHO
		Total	81	81	81		
Somerset	007	*Oct. 2005 – Dec. 2009*	44	47	47	44	EPA ECHO

MassDEP SERO, records were obtained from the Massachusetts Department of Environmental Protection Southeast Regional Office; EPA ECHO, records were obtained from the U.S. EPA Enforcement and Compliance History Online database; NR, parameter not reported

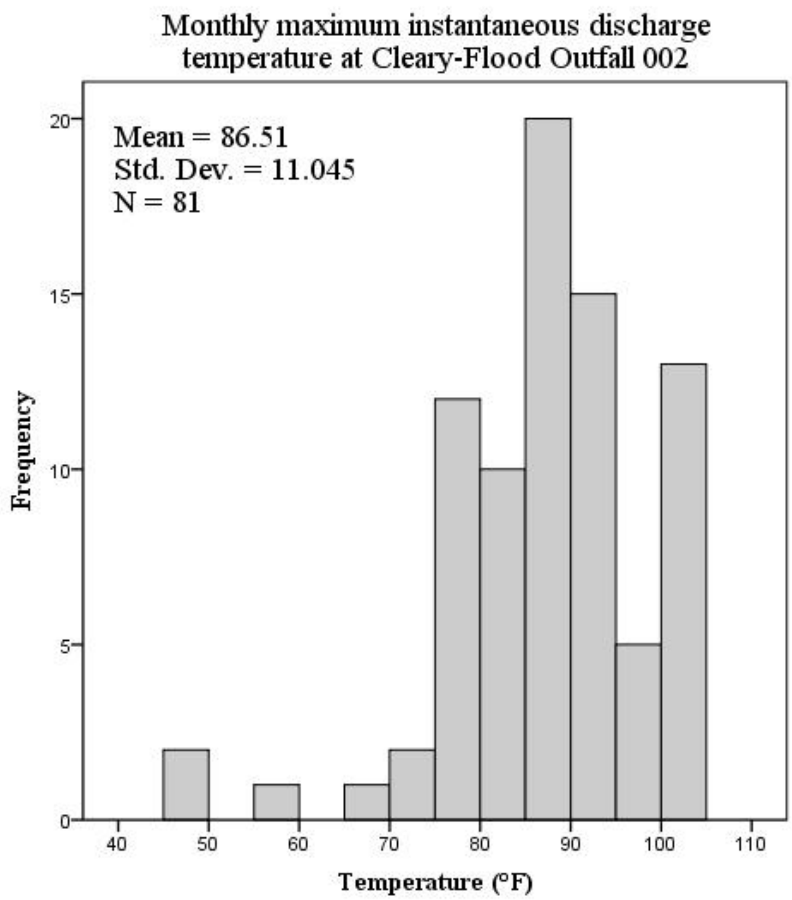
Two distinct groups are visible in the data, which is a possible indication that absolute maximum discharge temperatures may occur during summer periods. Cleary-Flood Outfall 001 has a ΔT limitation, which would be a limiting factor during periods of peak generation, specifically winter and summer months. The seasonal effect would be especially transparent at a peaking facility, which Cleary-Flood is. Of note are the six instances, shown as the right-most bar, where effluent temperature was between 90-94 °F. All of these observations were 90 °F, which may explain the asymmetry of the graph and the fact that no alleged violations of the 90 °F limit for Outfall 001 are on record.

Figure 9. Histogram of maximum instantaneous effluent temperatures observed each month at Cleary-Flood 001 (1994-1999, 2005-2010).



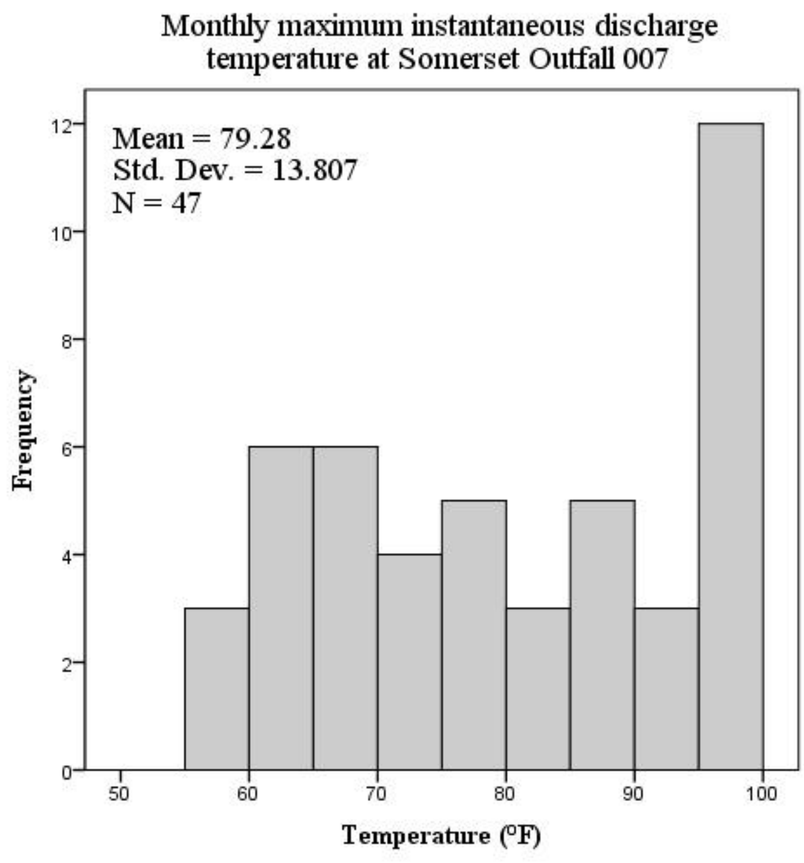
With the exception of a few observations in the 45-69 °F range, most of the maximum observed effluent temperatures at Cleary-Flood Outfall 002 are somewhat normally distributed about a mean of 86.5 °F; many have exceeded the temperature limitation of 90 °F. Heated effluent from the boilers for Unit 8 and Unit 9 mix with heated effluent from auxiliary cooling systems, as well as with unheated effluent from other plant systems combine at Outfall 002 before entering the Discharge Creek.

Figure 10. Histogram of maximum instantaneous effluent temperature observed each month at Cleary-Flood Outfall 002 (1994-1999, 2005-2010).



Maximum effluent temperatures at Somerset Outfall 007 show no clear pattern apart from being highly weighted at the upper end, near the maximum effluent limitation of 100 °F. The power plant has on multiple occasions reported discharging its effluent at a temperature of 100 °F, but no higher, and has—according to the NPDES records that were on file—stayed within its limit.

Figure 11. Histogram of maximum instantaneous effluent temperatures observed each month at Somerset Outfall 007 (2005-2009).



Maximum temperature rise through condenser

DMRs also provide the maximum instantaneous net temperature difference, ΔT, between the intake temperature and the discharge temperature (F°), for Cleary-Flood Outfall 001 and Somerset Outfall 007. Cleary-Flood Outfall 002 had no ΔT restrictions. The change in temperature between the intake and outfall is defined by the following general equation:

$$\Delta T = T_d - T_i$$

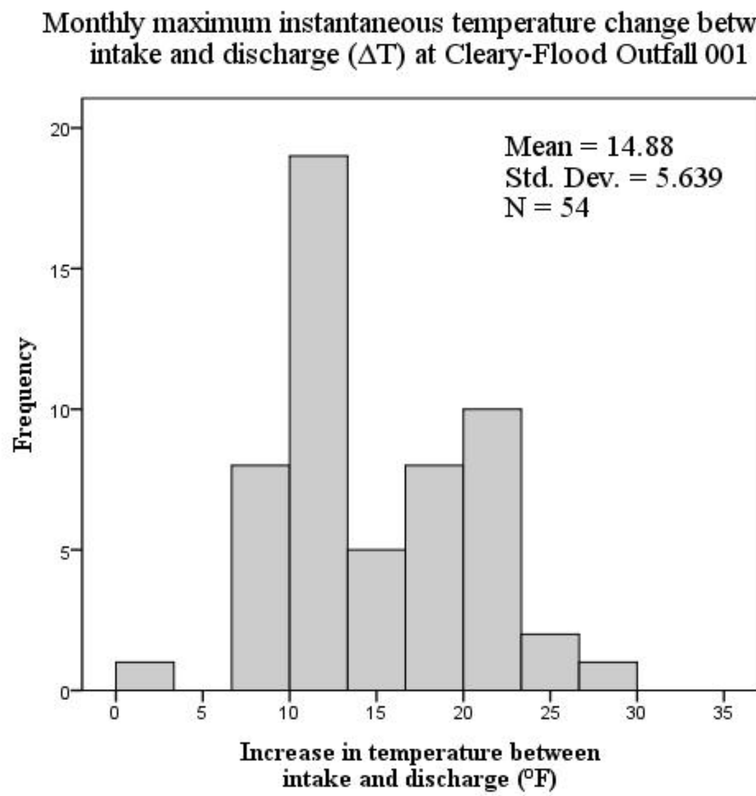
Equation 6. Net effluent temperature.

ΔT is the change in temperature, T_d is the temperature of the effluent water, and T_i is the temperature of the water at the point of intake.

Note that intake temperatures (i.e., ambient water temperatures, T_i) cannot be accurately inferred from the DMRs. A *maximum* ΔT is reported, not an *average* ΔT. Meanwhile, *maximum* instantaneous effluent temperature (T_d) is reported, not the *average* effluent temperature. Simply put, a maximum ΔT can occur when the absolute temperature of the effluent is not at a maximum. Similarly, the maximum instantaneous effluent temperature can occur when ΔT is not at its maximum. The result is that T_i is always unknown to a person reviewing the DMRs. Also note that theory suggests that power generation is strictly dictated by the ΔT of the cooling water through the condenser, and should be predictable and easily regulated.

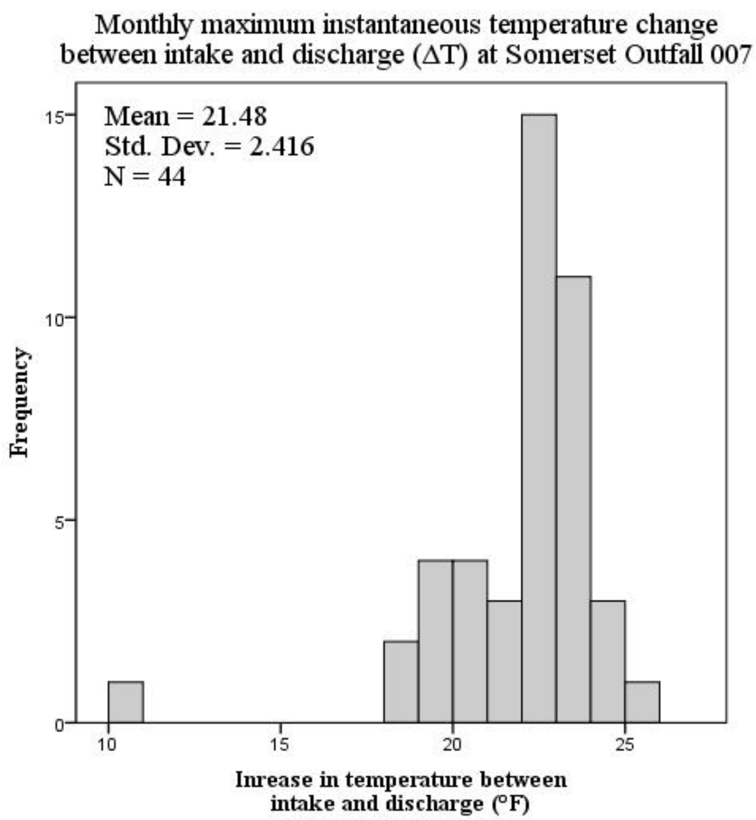
The distribution of ΔT at Cleary-Flood Outfall 001 is centered about a mean roughly 15 F°, but is only somewhat normally distributed. Nearly all values fall well below the temperature rise limit of 30 F°. The irregularity of the distribution may be a consequence of the fact that Cleary-Flood is a peaking facility, and operates sporadically. The NPDES permit for Cleary-Flood does not require reporting of ΔT for Outfall 002.

Figure 12. Histogram of maximum instantaneous difference between intake and discharge temperatures at Cleary-Flood Outfall 001 (1994-1999, 2005-2010).



With the exception of one abnormally low ΔT value, the distribution of observed values for the difference between intake and discharge temperature at Somerset Outfall 007 is fairly normally distributed about a mean of 21.5 F°, with the most common two values observed being 22 and 23 F°. For a base load power plant, it is not surprising to see that the ΔT values have a degree of regularity, because the power plant operates on a regular basis. The most common ΔT values are likely a consequence of the specific design of the plant, its operational conditions, and the activities of the power plant operators.

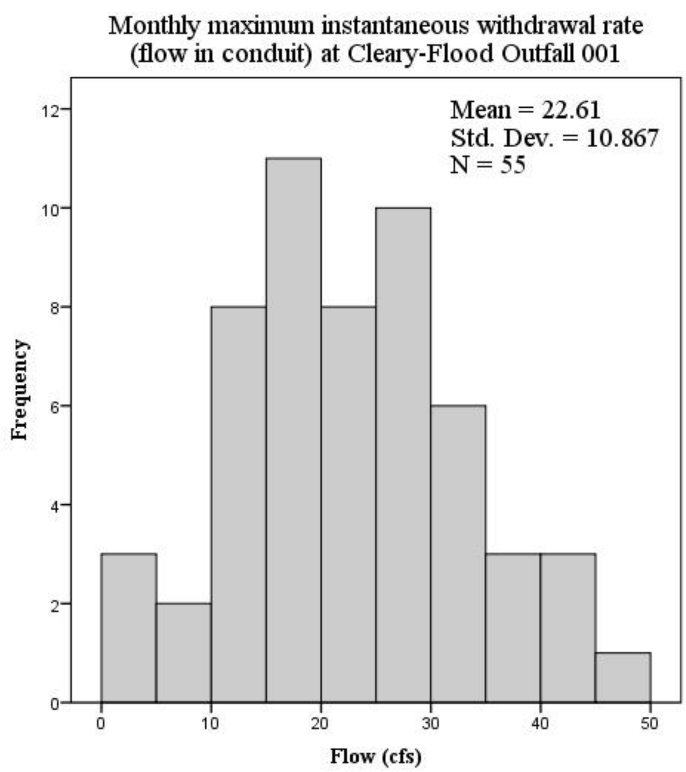
Figure 13. Histogram of maximum instantaneous difference between intake and discharge temperatures at Somerset Outfall 007 (2005-2010).



Maximum rate of flow in conduit

Maximum daily flow rate must be reported for Outfalls 001 and 002 at Cleary-Flood, and for Outfall 007 at Somerset. Because of pronounced skewness, the data were log10-normalized for Cleary-Flood Outfall 002. Maximum rate of flow “in conduit” is used synonymously with “withdrawal rate,” and is often used as a proxy for “rate of discharge” at once-through facilities. Small system leaks and downstream evaporative loses ensure that water consumption at once-through facilities is not zero, but here withdrawal rate is assumed to equal discharge rate.

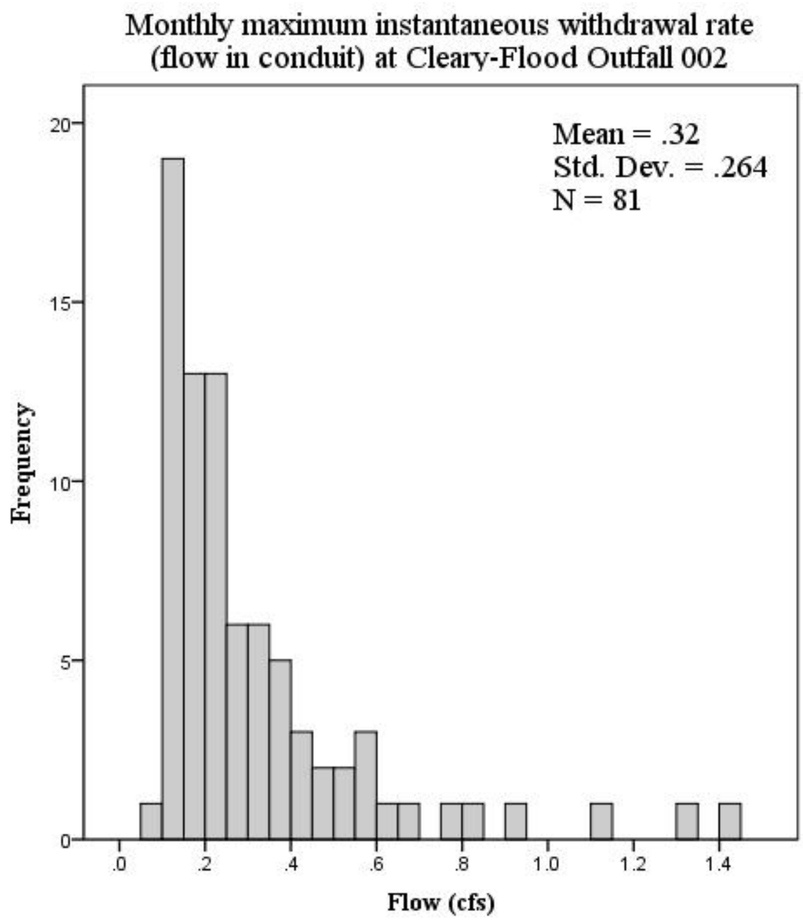
Figure 14. Histogram of maximum instantaneous flow through Cleary-Flood Outfall 001 (1994-1999, 2005-2010).



Maximum flow rate at Cleary-Flood Outfall 001 is fairly normally distributed, and perhaps as well as may be expected with 55 observations. The maximum instantaneous flow rate appears to have remained well below the current limitation of 55.7 cfs and the earlier limitation of 61.1 cfs over the period of interest, with only one instance where the maximum rate of flow reached a value between 46-50 cfs. Flow rates are fairly continuous, meaning that they can be any value and that power plant operators have a high degree of control of the flow rates.

Maximum instantaneous flow rate through Cleary-Flood Outfall 002 is considerably skewed, which is potentially the result of non-cooling water flows, auxiliary equipment water requirements, cleaning water flows, or storm water flows. Given the ambiguity of the reporting structure in this regard, it is not possible to distinguish the various system flows from one another. The result is that a substantial amount of unpredictable variation may be introduced in the pattern of flows through Outfall 002.

Figure 15. Histogram of maximum instantaneous flow through Cleary-Flood Outfall 002 (1994-1999, 2005-2010).



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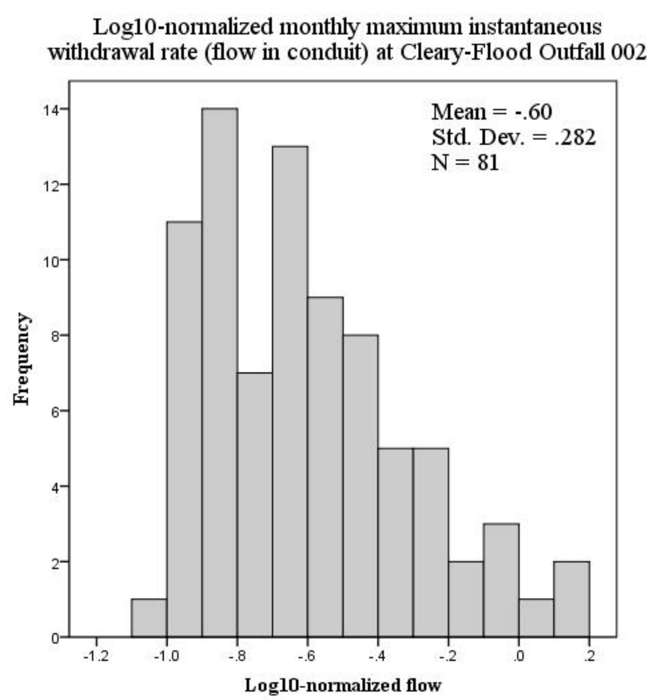
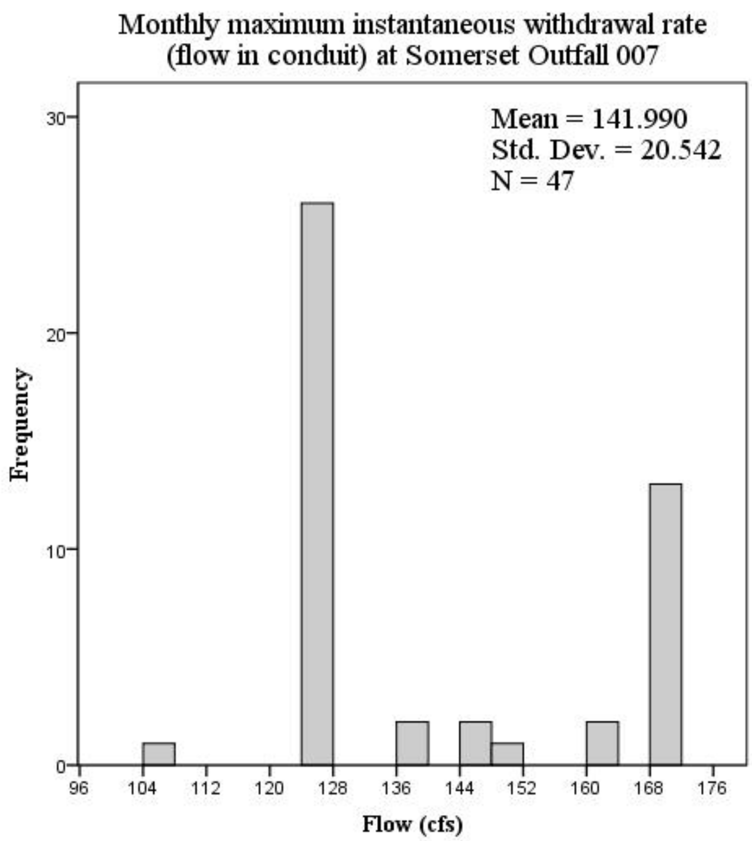
A commonly used normalization technique for highly skewed data is transforming the value into a power of ten or other base number. For instance, log10-normalization streamflow data can add clarity and predictability to a process that can be distorted by high flow events (e.g. heavy rainfall) and by the fact that flows cannot be less than zero. The effect of log10-normalizing the distribution of monthly maximum instantaneous withdrawal rates for Outfall 002 is a more normal distribution. Some skewness is still evident, but is less pronounced. While the log10-normalized flow rates are continuously distributed, it is difficult to say for certain whether the power plant operators have a high degree of control over the rate of flow, if only because of the fact that multiple networks, including storm drainage, contribute to the flow value.

Figure 16. Histogram of log10-normalized maximum instantaneous flow through Cleary-Flood Outfall 002 (1994-1999, 2005-2010).



The distribution of maximum instantaneous flow values at Somerset Outfall 007 highlights several points. First, the rate of flow is not continuously variable, because the flow can only be one of a handful of values. For instance, the most common flow rate for the study period, by far, was 127 cfs. The second most common flow rate was 172 cfs. Both are far below the current NPDES permit limitation of 309, and very far below the earlier limitation of 579 cfs. The lack of variation may be due to several things. One possibility is that flow rate can only be regulated by turning on or off individual pumps, rather than increasing or decreasing flow for individual pumps.

Figure 17. Histogram of maximum instantaneous flow through Somerset Outfall 007 (2005-2009).



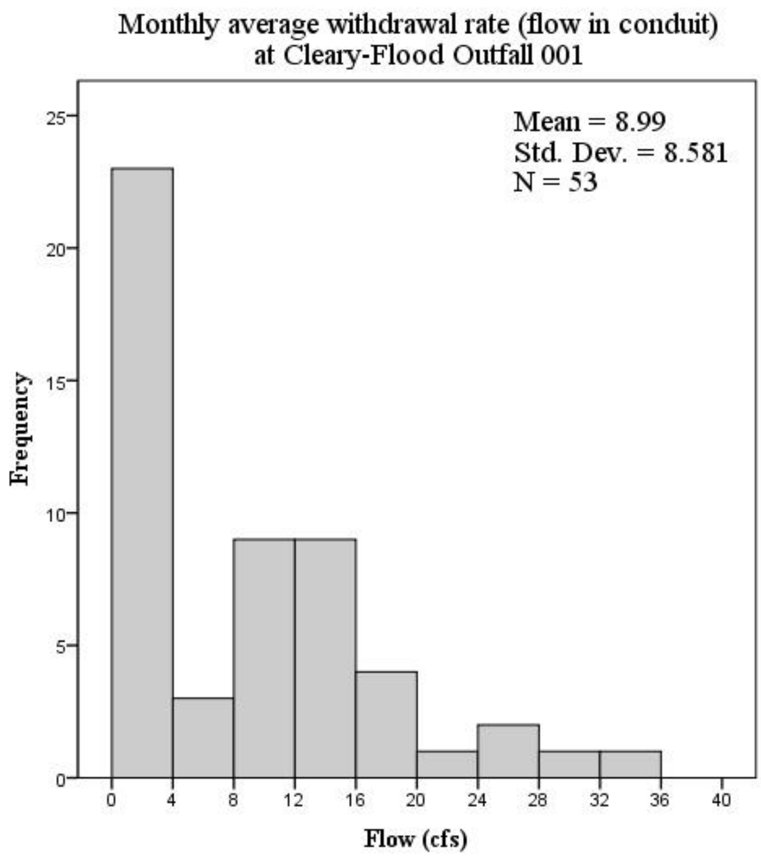
The method of obtaining the maximum flow rate may be prone to estimation errors, whereby the plant operator may report the rate based only upon the maximum flow ratings of the pumps, and with consideration to the maximum number of pumps operating at any given time during a single month. The specifics of the methodology for estimating maximum flow rates are not outlined in the permit. The relative lack of variation and the fact that the highest rate of flow ever observed at Somerset, 172 cfs, is far below the limitation of 309 cfs makes a linear model of the flow of limited practical value. Nonetheless, a later section describes the results of the attempt and briefly describes a way that the analysis may be improved by an alternative methodology.

Average rate of flow in conduit

Average rates of flow were reported for all three outfalls. The theory is that control of average withdrawal and discharge values will minimize the stresses experienced by fish and other aquatic organisms at the intake (e.g. impingement) and at the point of discharge (e.g. habitat loss due to scouring). For both Cleary-Flood outfalls, 001 and 002, histograms of flow values show substantial skewness and were log10-normalized accordingly. Flow rates at Somerset Outfall 007 were normally distributed and required no normalization.

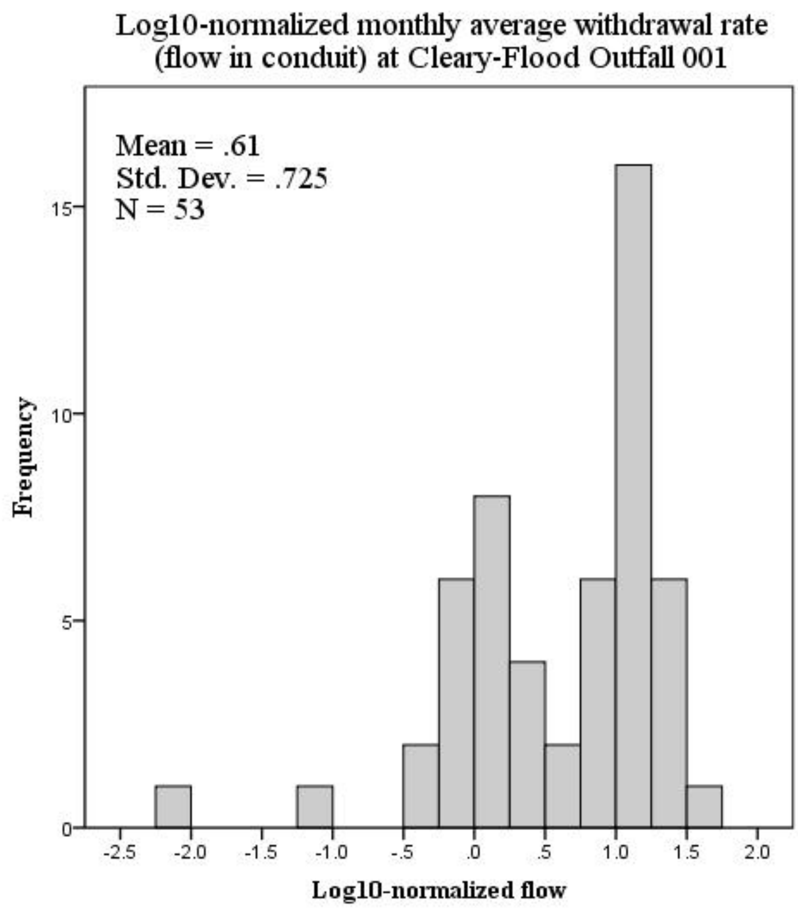
A histogram of the monthly average “withdrawal” (i.e., withdrawal/discharge) rates at Cleary-Flood Outfall 001 show skewness in the positive direction. Most rates fall between 0-15 cfs. Cleary-Flood was given a 2.5-month-long informal grace period to come into compliance after its permit was modified in late 2006, so its average withdrawal rate actually exceeded the standards set forth by the 2006 permit for the first month, but the power plant quickly came into compliance with its new seasonal limitations on average withdrawal rates.

Figure 18. Histogram of monthly average flow through Cleary-Flood Outfall 001 (1994-1999, 2005-2010).



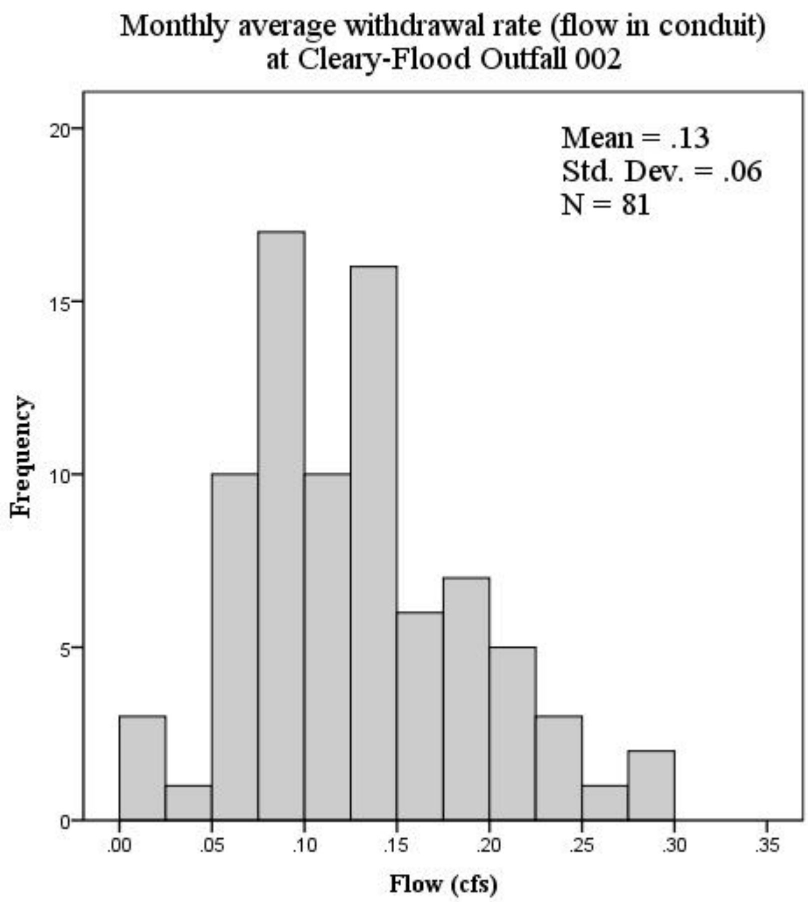
The distribution of monthly average withdrawal rates for Outfall 001 are improved by log10-transformation. It also reveals a permit-related grouping of average discharge rates, indicated by the two distinct peaks, discussed in a later section.

Figure 19. Histogram of log10-normalized monthly average flow through Cleary-Flood Outfall 001 (1994-1999, 2005-2010).



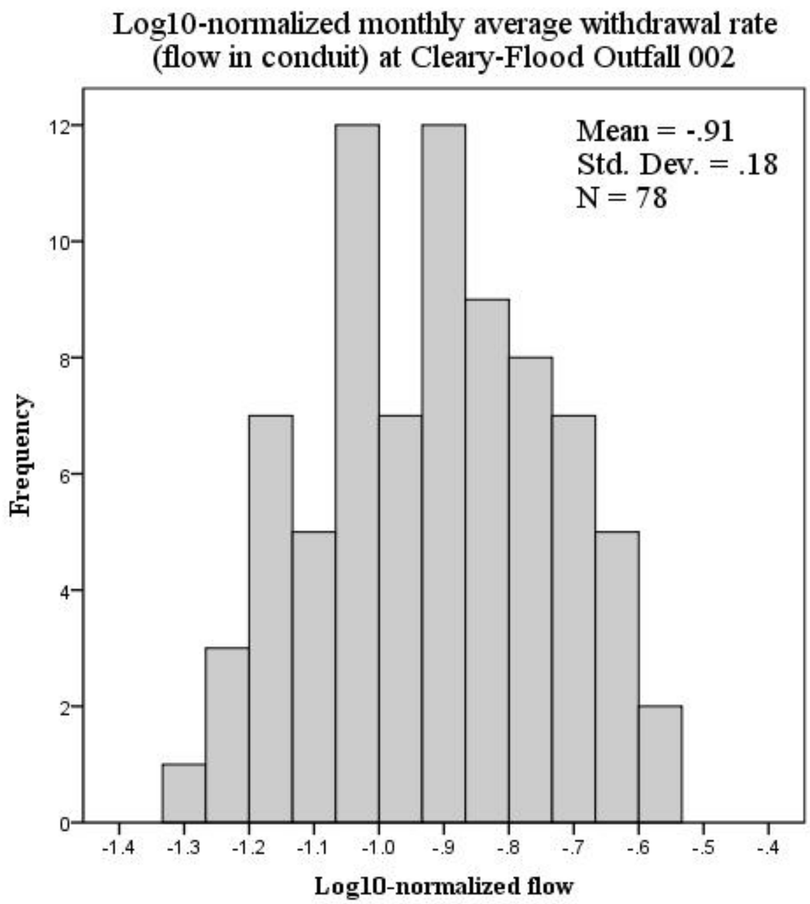
Average flow through Outfall 002 was generally much smaller than through Outfall 001, and slight skewness is still evident. Flow appears not to have ever gone above 0.30 cfs—less than the 0.37 cfs limitation and the earlier limitation of 0.39 cfs.

Figure 20. Histogram of monthly average flow through Cleary-Flood Outfall 002 (1994-1999, 2005-2010).



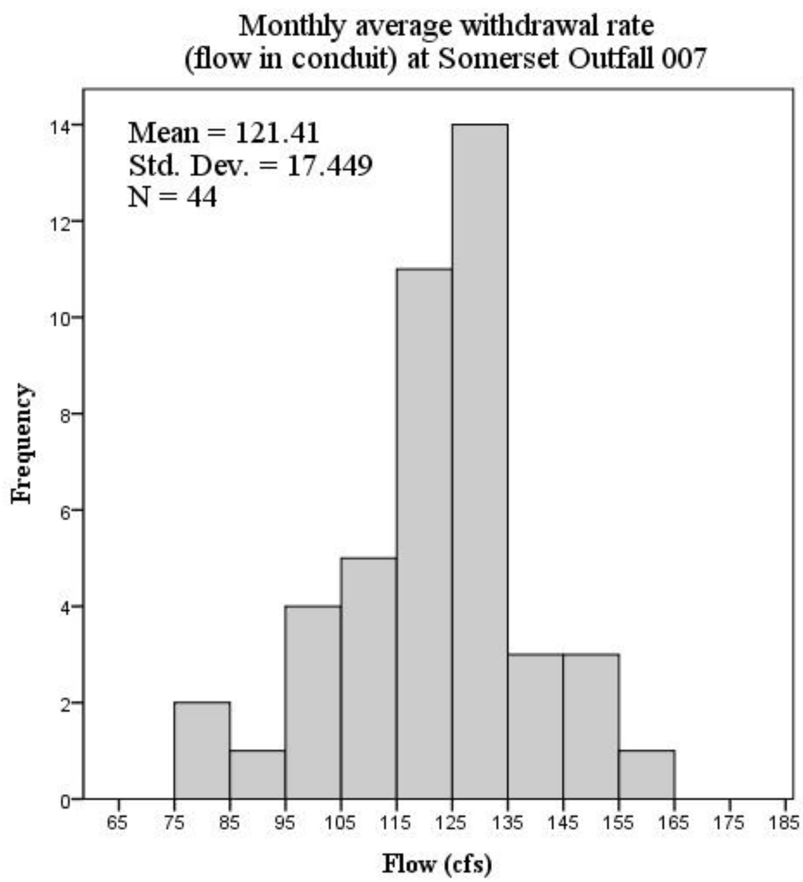
Log10-normalization improved the shape of the distribution. Flow values of zero cfs were excluded. There is no obvious seasonality in the average flow values through Outfall 002, as may be evident in Figure 19, which shows log10-normalized flow values through Outfall 001.

Figure 21. Histogram of log10-normalized monthly average flow through Cleary-Flood Outfall 002 (1994-1999, 2005-2010).



The distribution of monthly average "flow in conduit" values at Somerset Outfall 007 is fairly normally distributed, with the most common rates falling between 115-135 cfs and centered about a mean of approximately 121 cfs. No log10-normalization was necessary to prepare the data for MLR analysis.

Figure 22. Histogram of monthly average flow through Somerset Outfall 007 (2005-2009).



Data: explanatory variables

By necessity, data variables used to explain observed cooling water flow rates and effluent temperatures came from a variety of different sources. The explanatory variables addressed in the following sections include ambient air temperature, ambient water temperature, average stream depth at site, electricity demand (i.e. generation), streamflow, average salinity, tidal height, and insolation. While not all data were available, and while the data varied in terms of quality and temporal resolution, they are generally of a higher quality than those used in other studies. Some approximations and transformations were necessary to align values and to give a consistent spatial resolution (i.e., plant-specific) and temporal resolution (i.e., monthly). The temporal resolution was limited to a unit of one month, because monthly observations are reported to environmental regulators. Specific values are shown as Table A2 in the Appendix for the parameters that proved to be significant, and which are discussed in a later section.

Ambient air temperature

Consistent with Miller et al. (1992), Dziegielewski and Bik (2006), Yang and Dziegielewski (2007), and Elcock et al. (2010), ambient air temperature was chosen as a possible determinant of cooling water withdrawal rates and effluent temperatures. Specifically, the average of daily high temperatures at each plant was calculated for each month.

First, five National Climate Data Center (NCDC) maintained temperature gauges nearest to Cleary-Flood and Somerset were identified and mapped in ArcGIS. Access to most NCDC climate data is available through .gov and .edu IP addresses (NCDC, 2011). Temperatures were reported at the hourly timescale, so the highest temperature for each day at each site was identified.

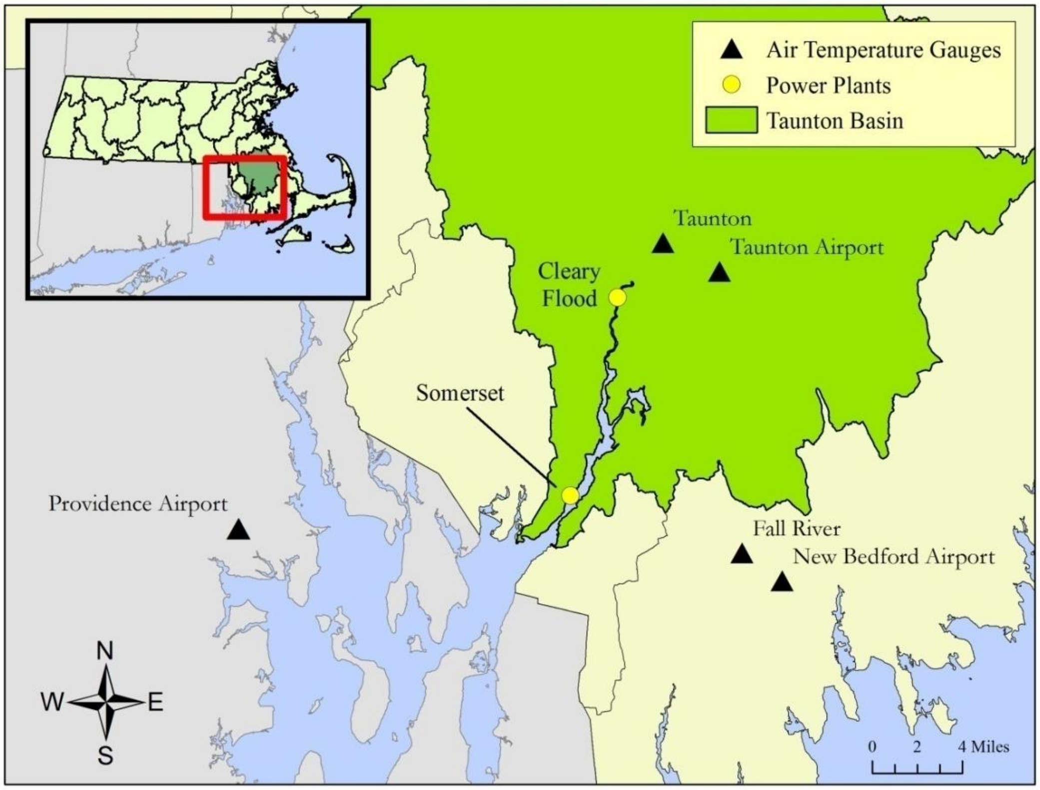
The air temperature gauges completely surround the power plants. This layout reduces uncertainty in estimating the temperatures. Table 4 shows that records were rarely available at all 5 gauges for any given day during the period of interest, 1970-2010, but also that no day was without at least one temperature reading.

Table 4. Air temperature stations, identification number, coordinates, distances from Cleary-Flood and Somerset, in service dates, and elevation.

Name	ID	Lat.	Long.	Cleary-Flood (ft)	Somerset (ft)	In Service Dates	Elev. (ft)
Taunton	198367 (COOP)	41°54'	-71°04'	16,650	63,112	*Jun 1948-Oct 2007*	20
Taunton Airport	54777 (WBAN)	41°53'	-71°01'	24,676	63,071	*Nov 1997-Present*	43
Fall River	192642 (COOP)	41°43'	-71°08'	66,680	42,456	*Jun 1948 – Apr 1976*	190
New Bedford Airport	94726 (WBAN)	41°41'	-70°58'	76,929	53,576	*Jan 1947-Present*	80
Providence Airport	376698 (COOP)	41°43'	-71°26'	104,190	78,321	*Jun 1932 - Present*	60

Cleary-Flood and Somerset indicate distances between air temperature station and the respective power plant; COOP and WBAN are different standard identification systems.

Figure 23. Map of air temperature stations, case study power plants, and Taunton River basin.



An inverse distance interpolation, which gives weight to air temperature readings based on a gauge's nearness to the ungauged site, was used to estimate daily high air temperatures at Cleary-Flood and Somerset stations. The closer an air temperature station is to the power plant, the greater the influence on the estimation. The formula for inverse distance weighting is modified from Shepherd (1968). The historical air temperature at Cleary-Flood was estimated according to the following equation:

$$T_{CF} = \left(T_T \times \frac{\frac{1}{D_{T,CF}}}{\sum\frac{1}{D_{CF}}}\right) + \left(T_{TA} \times \frac{\frac{1}{D_{TA,CF}}}{\sum\frac{1}{D_{CF}}}\right) + \left(T_{FR} \times \frac{\frac{1}{D_{FR,CF}}}{\sum\frac{1}{D_{CF}}}\right) + \left(T_{NB} \times \frac{\frac{1}{D_{NB,CF}}}{\sum\frac{1}{D_{CF}}}\right) + \left(T_P \times \frac{\frac{1}{D_{P,CF}}}{\sum\frac{1}{D_{CF}}}\right)$$

Equation 7. Modified inverse distance interpolation (Shepherd, 1968) to estimate historical daily air temperatures at Cleary-Flood.

Similarly, the historical temperature at Somerset was calculated in the following way:

$$T_S = \left(T_T \times \frac{\frac{1}{D_{T,S}}}{\sum\frac{1}{D_S}}\right) + \left(T_{TA} \times \frac{\frac{1}{D_{TA,S}}}{\sum\frac{1}{D_S}}\right) + \left(T_{FR} \times \frac{\frac{1}{D_{FR,S}}}{\sum\frac{1}{D_S}}\right) + \left(T_{NB} \times \frac{\frac{1}{D_{NB,S}}}{\sum\frac{1}{D_S}}\right) + \left(T_P \times \frac{\frac{1}{D_{P,S}}}{\sum\frac{1}{D_S}}\right)$$

Equation 8. Modified inverse distance interpolation (Shepherd, 1968) to estimate historical daily air temperatures at Somerset.

T_P = air temperature at Providence Airport
T_{FR} = air temperature at Fall River
T_T = air temperature at Taunton
T_{TA} = air temperature at Taunton Airport
T_{NB} = air temperature at New Bedford Airport

$D_{P,CF}$ = distance from Providence Airport to Cleary-Flood
$D_{FR,CF}$ = distance from Fall River to Cleary-Flood
$D_{T,CF}$ = distance from Taunton to Cleary-Flood
$D_{TA,CF}$ = distance from Taunton Airport to Cleary-Flood
$D_{NB,CF}$ = distance from New Bedford Airport to Cleary-Flood

$D_{P,S}$ = distance from Providence Airport to Somerset
$D_{FR,S}$ = distance from Fall River to Somerset
$D_{T,S}$ = distance from Taunton to Somerset
$D_{TA,S}$ = distance from Taunton Airport to Somerset
$D_{NB,S}$ = distance from New Bedford Airport to Somerset

Additionally,

$$\sum \frac{1}{D_{CF}} = \frac{1}{(D_{P,CF})} + \frac{1}{(D_{FR,CF})} + \frac{1}{(D_{T,CF})} + \frac{1}{(D_{TA,CF})} + \frac{1}{(D_{NB,CF})}$$

Equation 9. Summation of air temperature gauge distances to Cleary-Flood.

$$\sum \frac{1}{D_{S}} = \frac{1}{(D_{P,S})} + \frac{1}{(D_{FR,S})} + \frac{1}{(D_{T,S})} + \frac{1}{(D_{TA,S})} + \frac{1}{(D_{NB,S})}$$

Equation 10. Summation of air temperature gauge distances to Somerset.

A monthly mean of daily high air temperatures was calculated from the daily high air temperature estimates. Since data were generally unavailable from all stations for any given day, the sum of station distances used in the inverse distance interpolation *only included distances to stations that had records for the specific day*. Distances were estimated by plotting the stations and power plants in Google Earth and then using the ruler feature for manual measurement. Specific values for the monthly average of daily high air temperature values are available along with other parameters in Table A2 of the Appendix.

Box-plots of monthly averages of daily high air temperature estimates at Cleary-Flood and Somerset, while not identical, are very similar. Any differences between Figure 24 and Figure 25 are due to the differences in distances from the two power plants to the various temperature gauges and to the natural air temperature variation at the gauges themselves.

Seasonal trends are clear in both figures with daily high air temperatures around 80 ºF during the warmest months of the year and daily high air temperatures near 40 °F during the coldest months of the year. A histogram showing daily high air temperatures, not shown would be normally distributed.

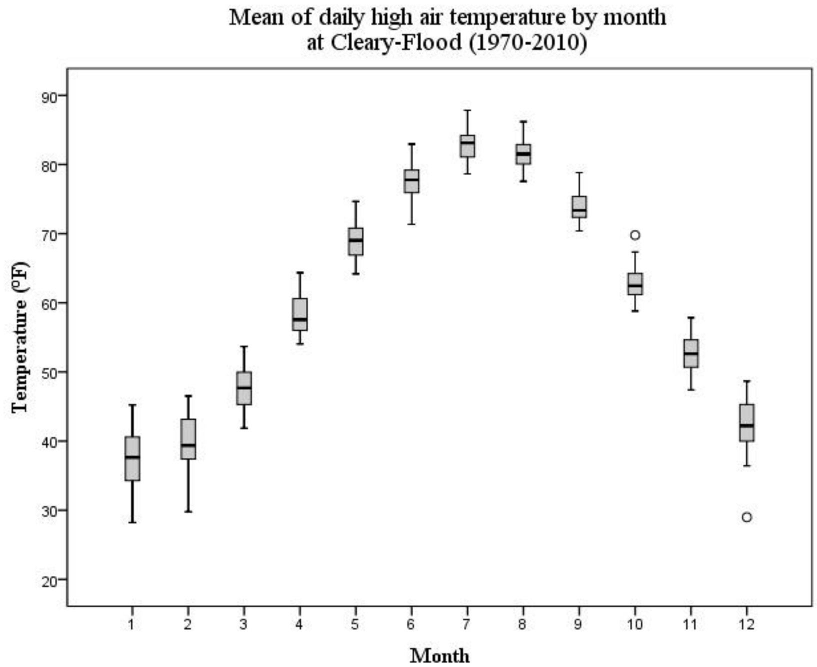
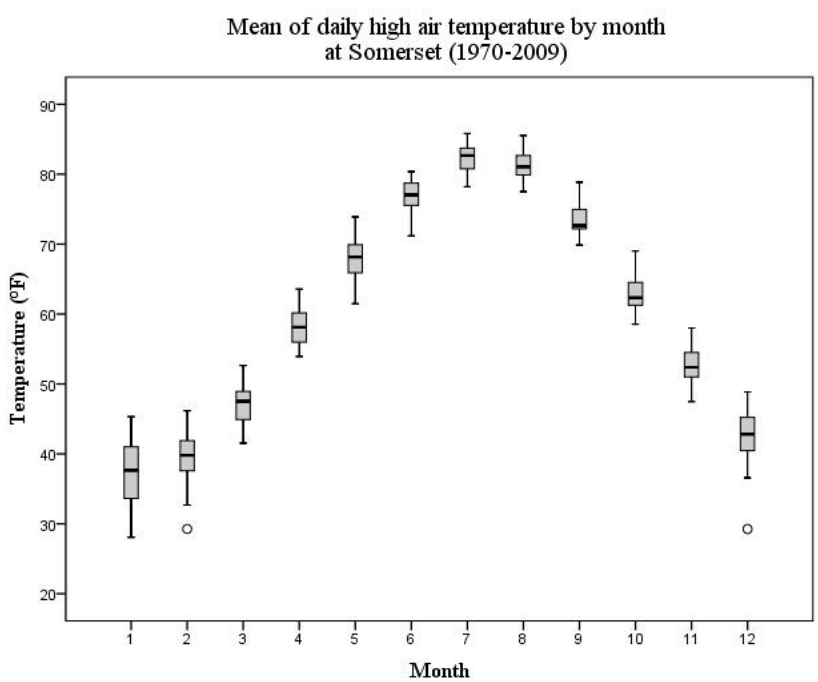


Figure 24. Box-plots of estimated mean of daily high air temperature by month at Cleary-Flood.

Figure 25. Box-plots of estimated mean of daily high air temperature by month at Somerset.



Ambient water temperature

As Backus and Brown (1975) show, the rate of water withdrawal per MW of electricity needed for cooling in a once-through facility is theoretically dictated by thermodynamic efficiency of the plant, and by the temperature rise of the water as it flows through the condenser (Equation 3). The reverse is also true, and probably captures the causes and effects of power plant operations better: the temperature rise through the condenser is dictated by the rate of flow through the condenser. Assuming that thermodynamic efficiency and power plant capacity are unvarying, the only action that would change the ΔT through the cooling system is the rate of flow. As Equation 6 shows, the absolute temperature of the discharge, T_d, depends on the ΔT and the temperature of the water at the intake, T_i. Therefore, there is a good chance that ambient water temperature would be the best predictor of effluent temperatures and, where effluent temperature limitations are strictly observed, perhaps a predictor of cooling water flow rates. So, why not directly use water temperatures in the model?

The simple answer is that the public record of water temperatures at the plants is woefully incomplete. Furthermore, building a model based solely on hard-to-get data points, one that is insensitive to real data constraints, leads to limited overall applicability of the model and an additional expense (e.g. time, money) for those who would wish to use it.

The EIA-767 does report intake and discharge temperatures, but the methodology with which the temperatures are collected are unclear and they are only available as annual averages. The values are good for inferring broad conclusions, and for doing inter-facility comparisons, but not for understanding plant-specific variation. The EIA-767 was insufficient for the purposes of this study.

To revisit an earlier point, it would be tempting to try to infer ambient water temperature from the NPDES DMRs. Water temperature cannot be inferred from ΔT and the reported maximum instantaneous discharge temperature (i.e., max effluent gross value, maximum T_d). Maximum effluent net value is provided, not the net value when the effluent gross temperature value was also at a maximum. For instance, if the max effluent gross value was 78 ºF, and the maximum net temperature between the intake and outfall was reported as 10 F°, the ambient water temperature, T_i, would be calculated as 68 ºF. However, the ambient temperature could have been much higher when the maximum T_d occurred, such as 77 °F, making the actual ΔT only 1 F°. It could also have been much lower when the maximum value occurred, for the same reasons.

In the case of Cleary-Flood and Somerset, the only water temperature values available that were of sufficient temporal resolution (i.e., at least average monthly), came from a National Oceanographic and Atmospheric Administration (NOAA) gauge at the mouth of the Taunton River. This direction of MLR development was not pursued for a variety of reasons. Apart from the obvious fact that water temperatures can vary greatly over very small distances, vertical and horizontal, it was clear from a review of water temperature gauges that they are much less common than air temperature and flow gauges, and that they are typically placed irrespective of power plant locations. More importantly, Miller et al. (1992) shows that ambient air temperature is highly linearly correlated with water temperature. Ambient air temperature serves as a sufficient proxy for ambient water temperature where no unusual inflows are present and where insolation is consistent over large areas.

Average stream depth at intake

In a natural and tidally influenced stream, depth is a function of streamflow, tidal height, and cross-sectional stream profile. Any variation in depth is a function of streamflow and tidal variation—both of which were addressed in model development. Of potentially greater concern are the conditions at the intakes and outfalls. For instance, how deep are they? The EIA-767 survey asked power plant operators to give a value for the depth, but with no specific methodology or datum. The depth of the intake would vary for the same reasons that stream depth varies, so the survey question itself was flawed. In fact, a disproportionately high number of respondents reported intake depths of 10 feet (NETL and DOE, 2009), like the result of estimation. The specific locations and approximate depths of the intakes and outfalls are not provided in the DMRs or in each plant's NPDES permit.

Electricity demand

Energy supply (i.e., generation) is used as a proxy for demand, because power plants respond to electricity requests from independent service operators by providing more power to the grid. When supply is much greater than demand, fuel and other resources are wasted, and when demand is much greater than supply, black outs and brown outs occur.

Cleary-Flood is a peaking plant, so the variability of ISO requests for energy generation are often obvious and directly related to the power plant’s operational efficiency. Meanwhile, Somerset is a base load plant, so it provides a consistent supply of electricity, but it can also increase or decrease its generation based upon demand.

The EIA provides monthly net electricity generation values at the generator level beginning in 1970 and running through 2010 in its EIA-906/920/923 database and archive files. Monthly net generation is defined as the gross electricity generation minus use by the power plant for primary systems, auxiliary equipment, and energy requirements for cooling water pumping. Monthly net generation estimates are based upon yearly generation for each plant reported by census, and regression equations based on monthly sampling of a subset of plants (EIA, 2011a; EIA, 2011b). Table A2 in the Appendix provides the complete list of energy generation values used. For both plants, some data interpretation was necessary to identify the specific generators that were used and to spot potential reporting errors. Cleary-Flood generation is discussed first, followed by a discussion of Somerset generation. Only non-zero generation values are reported here and used in the MLR analysis. In only a few cases were zero generation months accompanied by non-zero (i.e., positive) cooling water flow values or non-zero ΔT values at either plant. These were taken to be anomalous and not indicative of the general conditions at each plant.

Cleary-Flood is powered by two units, 8 and 9. Unit 8 is a Rankine cycle system that uses once-through cooling, has a capacity of 25 MW, and came online in 1965. It burns No. 6 and No. 2 fuel oil. Unit 9 is a combined cycle system consisting of a 20 MW combustion turbine-generator (air cooled) and a 90 MW steam boiler turbine generator that is cooled by a wet recirculating system. Unit 9 came online in 1975 and burns natural gas and fuel oil (U.S. EPA, 2006). For 2001 and 2002—years which did not list prime mover types (e.g. combined cycle versus steam cycle)—the steam turbine, once-through cooled system was assumed to burn distillate fuel oil (DFO). The closed-loop cooled component of the steam part of the combined cycle system (having a prime mover code of CA for other years) was assumed to be the system which burns residual fuel oil (RFO) and natural gas (NG). In all other years, the CA system generation is assumed to be cooled with closed-loop cooling and the steam cycle system is assumed to be the once-through cooled system. The steam cycle and CA values appear to have been switched in the 2003 data set. Ultimately, the MLR analyses were unaffected by the ambiguities for the 2001-2003 data, because those years were excluded due to a lack of effluent temperature and withdrawal rate values available from the Cleary-Flood DMRs.

Data for Cleary-Flood Unit 8 appeared to have been misreported for years prior to 1977. In order to verify this error, two analysis of variance (ANOVA) tests were performed comparing the set of generation values for 1970-1976 to generation values for 1977-2010. In the first test, reported Unit 8 values were tested for similarity to see if the differences in generation between year sets could have been due to chance alone. The generation values differed significantly between the two date ranges, F (1, 470) = 367.42, $p < 0.001$. In the second, reported total generation values (Unit 9 + Unit 8) were tested versus reported generation in Unit 8 prior to 1977. The results of the second ANOVA revealed that differences may have been due to chance alone, F (1, 470) = 1.197, p = 0.274, and were possibly an artifact of the EIA monthly generation calculation methodology.

It also seems unlikely that Cleary-Flood could have generated the same amount of energy at the plant before the larger combined cycle system was installed in 1975, so the differences may simply be a reporting error on the part of the EIA. Periods of transition (e.g. new NPDES limitations, new generator installations) appear to be particularly difficult for environmental and energy databases to capture accurately.

A summary table of the ANOVA test comparing 1970-1976 generation to 1977-2010 generation values for Unit 8 is available in the Appendix as Figure A3. A summary table of the ANOVA test comparing 1970-1976 generation to 1977-2010 total generation values (Unit 8 + Unit 9) is available in the Appendix as Figure A4.

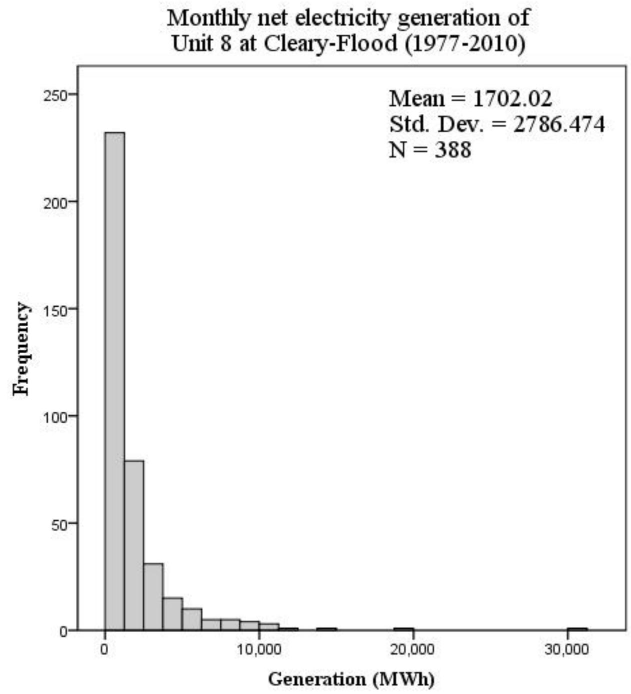
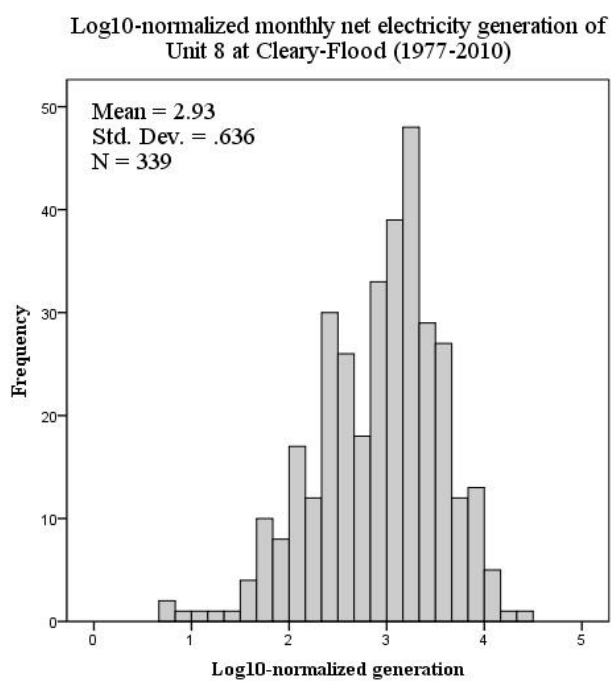


Figure 26. Histogram of monthly net energy generation of Cleary-Flood Unit 8 (1977-2010).

Figure 27. Histogram of log10-normalized monthly net energy generation of Cleary-Flood Unit 8 (1977-2010).



The distribution of Unit 8 monthly net energy generation was improved by a log10-normalization. The skewness of Figure 26 is not surprising, given the skewness of related DMR-reported values, and is indicative of the intermittency of Unit 8 generation due to Cleary-Flood's use as a peaking plant.

The skewness is also visible in a box-plot diagram of Unit 8 monthly net generation values by month, as is the high degree of variability and presence of outlier generation values for some months.

After log10-normalization, seasonal variation is more readily apparent, with the greatest generation occurring during the months with the most extreme air temperatures (i.e. winter, summer). A handful of very low generation months are also visible as outliers.

The skew of the distribution of monthly net energy generation values for Cleary-Flood Unit 9 was only moderately rectified by log10-normalization. The modification introduced skew in the opposite direction. The size difference between the two units, 8 and 9, is apparent from the differences of their mean generation. Unit 8 had a mean monthly net generation of 1,702 MWh, whereas Unit 9 had a mean monthly generation of 10,903 MWh. Nameplate capacity and number of hours in operation dictate the number of megawatt·hours of energy produced: megawatts (MW) × hours (h)= megawatt·hours (MWh).

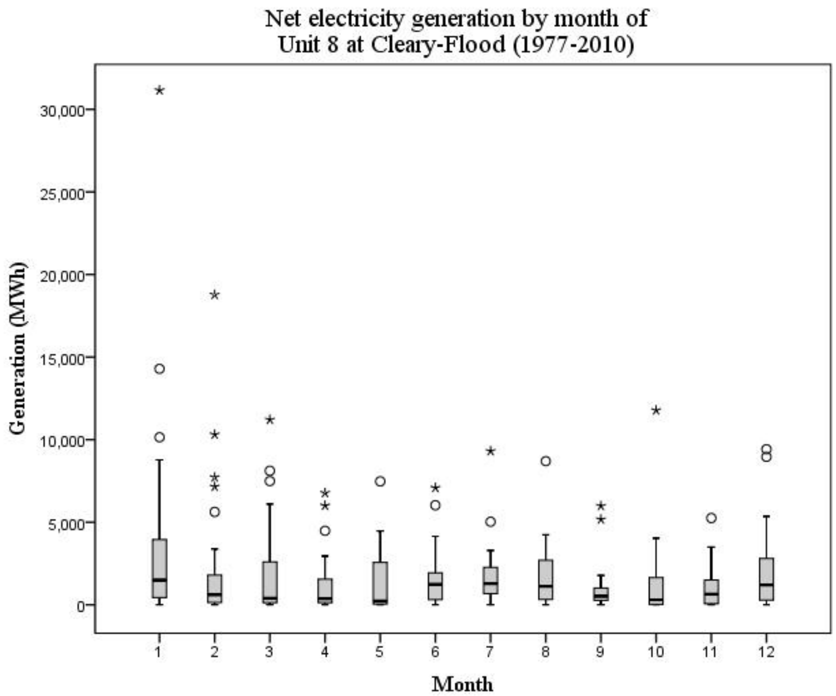
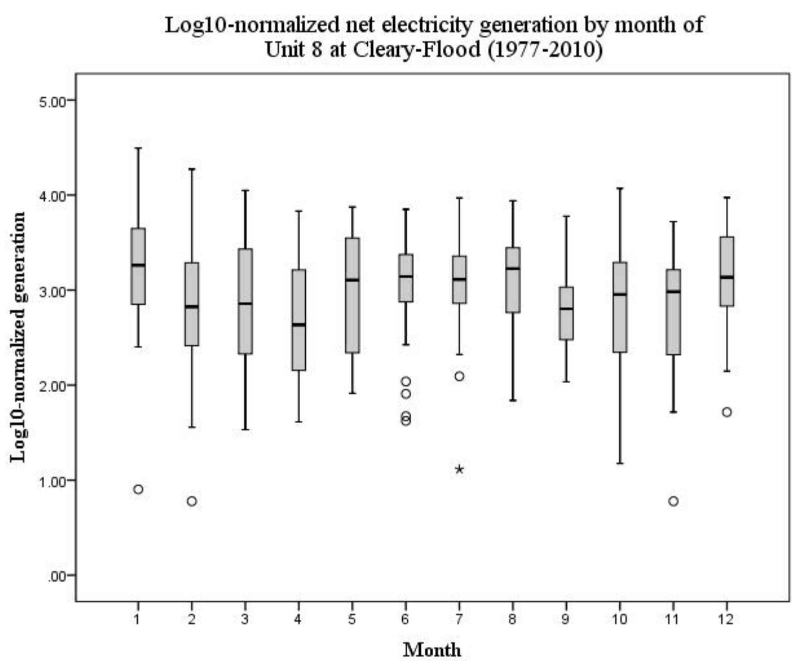


Figure 28. Box-plots of net energy generation of Cleary-Flood Unit 8 by month (1977-2010).

Figure 29. Box-plots of log10-normalized net energy generation of Cleary-Flood Unit 8 by month (1977-2010).



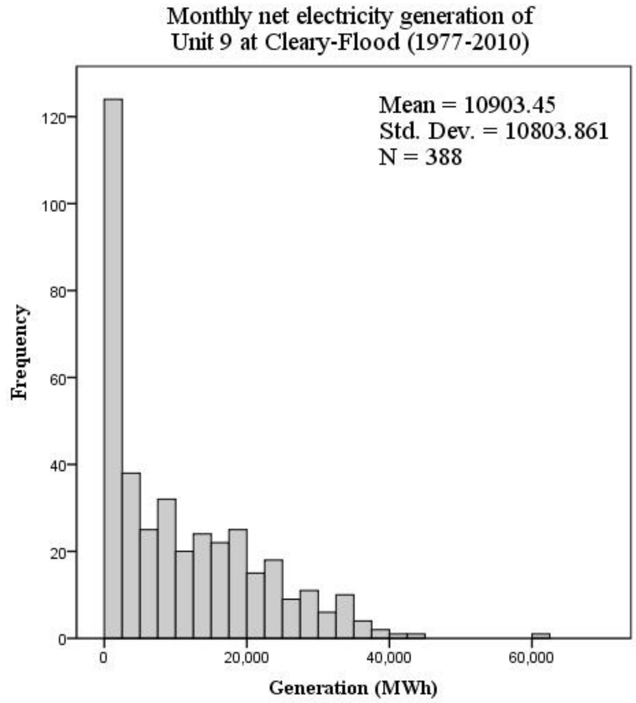
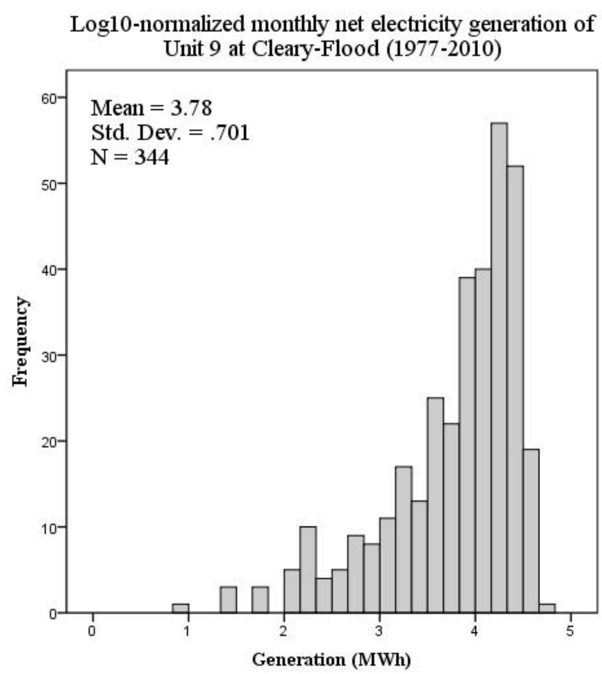


Figure 30. Histogram of monthly net energy generation of Cleary-Flood Unit 9 (1977-2010).

Figure 31. Histogram of log10-normalized monthly net energy generation of Cleary-Flood Unit 9 (1977-2010).



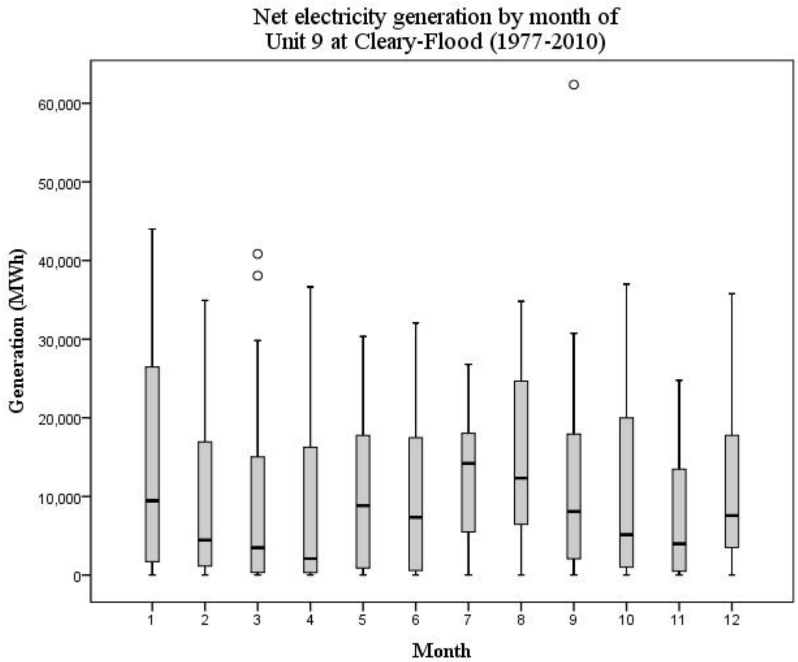
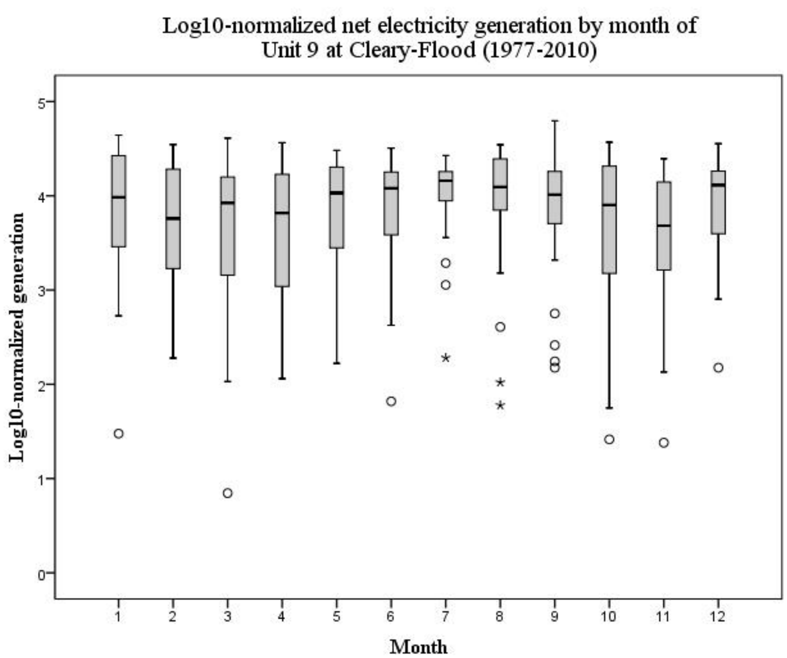


Figure 32. Box-plots of net energy generation of Cleary-Flood Unit 9 by month (1977-2010).

Figure 33. Box-plots of log10-normalized net energy generation of Cleary-Flood Unit 9 by month (1977-2010).



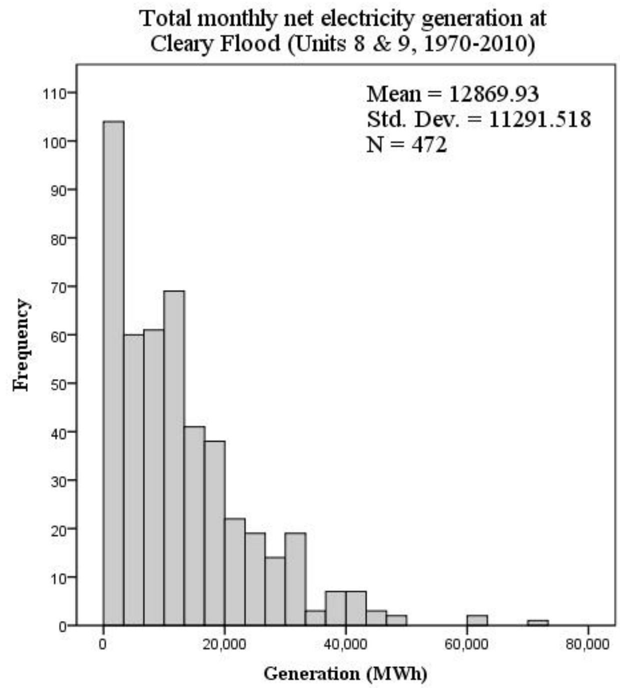
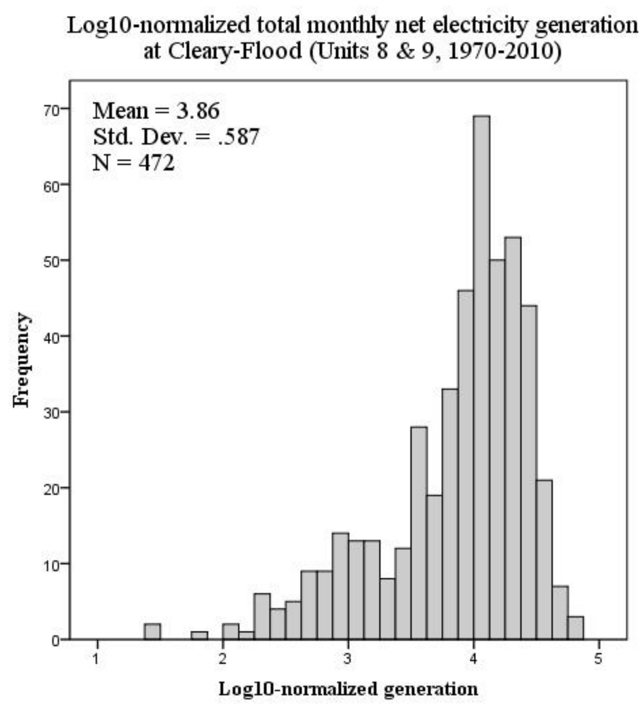


Figure 34. Histogram of monthly total net energy generation of Cleary-Flood Units 8 and 9 (1970-2010).

Figure 35. Histogram of log10-normalized monthly total net energy generation of Cleary-Flood Units 8 and 9 (1970-2010).



As expected the total net generation of Units 8 and 9 shows the same skewed distribution, with a mean slightly higher than the sum of the individual means of Unit 8 and Unit 9. The log10-normalized distribution is slightly skewed toward zero, and, in terms of its overall skewness falls between the roughly normally distributed Figure 27 and the slightly end-heavy Figure 31.

The following box-plots of the total net energy generation of Cleary-Flood Units 8 and 9 show the same seasonality of previous energy generation box-plots and the same skewness.

Figure 36. Box-plots of total net energy generation of Cleary-Flood Units 8 and 9 by month (1970-2010).

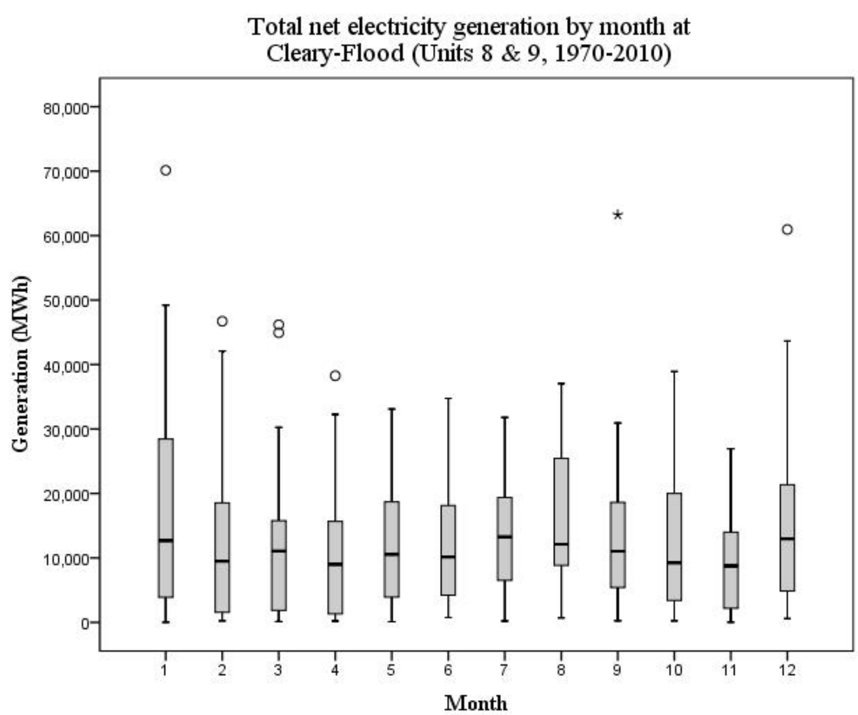
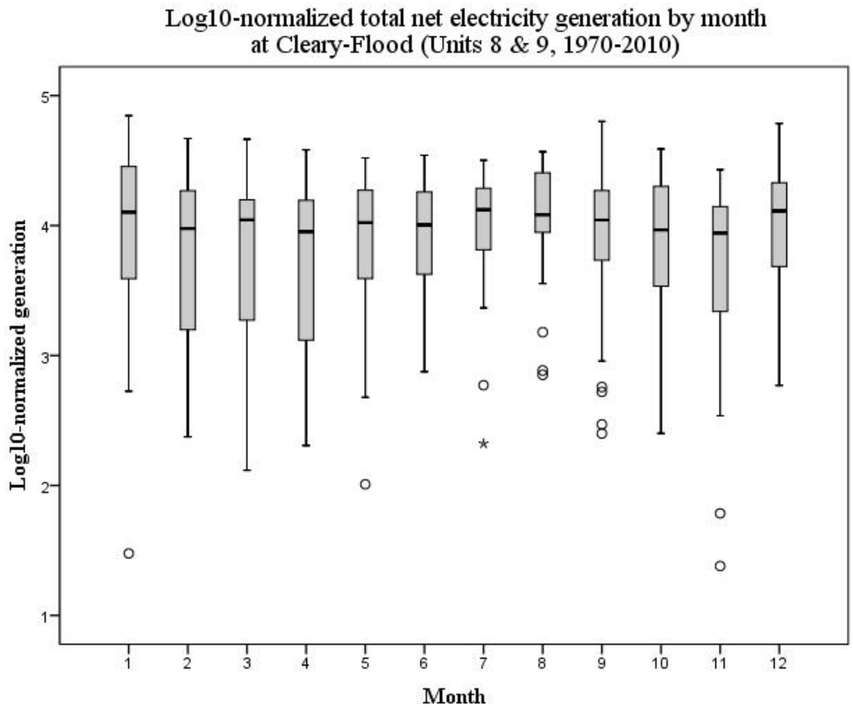


Figure 37. Box-plots of log10-normalized total net energy generation of Cleary-Flood



Somerset's monthly net energy generation was easier to interpret than Cleary-Flood's data in the EIA database of monthly energy generation values. Individual generating units were identified by prime mover and fuel type. According to the Somerset NPDES permit, Outfall 007 serviced both Unit 5 and Unit 6. Both units used steam-cycle technology and once-through cooling systems. They burned fuel oil and bituminous coal, respectively. Unit 5 was no longer active after 1994. As a point of clarification, prior to 1990, monthly generation values were reported in by the EIA in kWh, and then in MWh thereafter, but here all values are reported in MWh.

In 2001, the EIA updated its record keeping methodology for the Form-906, but the prime mover (i.e., steam cycle) was not listed. Again, periods of transition appear to be particularly difficult for large government databases. The prime mover was not listed in 2002, either. For those two years, the two generators that combusted RFO and bituminous coal (BIT) were assumed to be the steam cycle generators of interest and were therefore used in the model. The other fuel types listed were jet fuel (JF) and distillate fuel oil (DFO), which were combusted in Somerset's gas turbines. Again, gas turbine generators do not need water for cooling. The decision to select the RFO- and BIT-fired units was also motivated by the fact that net generation is historically higher for the steam cycle units than for the gas turbines at the plant.

Monthly net electricity generation is significantly higher at Somerset than at Cleary-Flood, which is due to Somerset's higher capacity and its use as a base load plant. The histogram of generation values over the period of interest, 1970-2009, is fairly normally distributed about a mean of 79,673 MWh. No substantial skewness is evident, although most months have a total generation of between 50,000 and 100,000 MWh, likely signifying the regularity of the power plant's operation. No log10-normalization was necessary.

Some seasonality is evident in the box-plots of total net electricity generation by month for Somerset, although it is less pronounced than it is at Cleary-Flood. Interestingly, the peak generation months appear to be during the winter, with no substantial variation occurring during the remaining months. High and low outliers are visible throughout the spring and early summer months. As with Cleary-Flood, months where generation was zero were excluded.

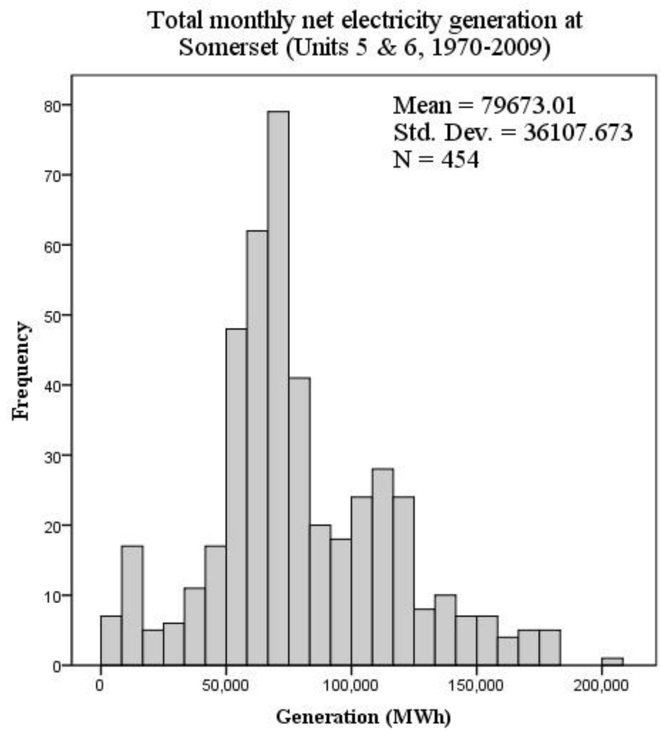
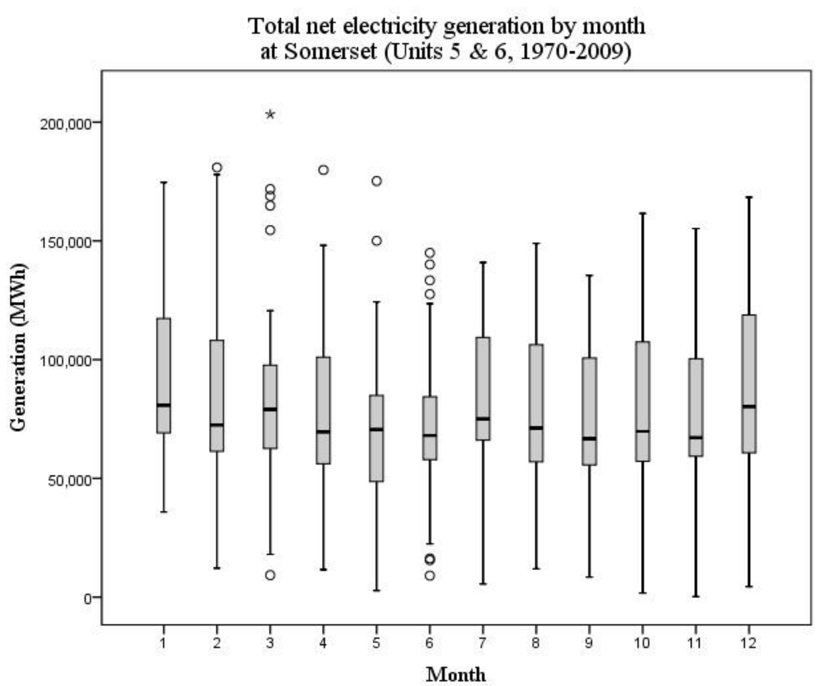


Figure 38. Histogram of monthly total net energy generation of Somerset Units 5 and 6.

Figure 39. Box-plots of total net energy generation of Somerset Units 5 and 6 by month.



Streamflow

Under a regime of constant heat input, a stream will experience a rise in temperature if streamflow decreases. For example, using the generalized heat rejection equation in Chapter 2, one finds that, *ceteris paribus*, a decrease in theoretical river flow, Q_1, would lead to a higher maximum allowable river temperature, T_2, as a consequence of exposure to heat inputs. Insofar as streamflow affects ambient water temperature, streamflow was chosen as a potential predictor of power plant effluent discharge temperatures and cooling water use rates. The rate of freshwater flow in the Taunton River at each of the two power plants was an important, but problematic parameter to estimate. Streamflow can be highly variable, especially for undammed streams, and may substantially contribute to the influence of air temperatures and solar radiation on water temperature (Miller et al., 1992).

There are no long-term flow gauges at either of the power plant water use sites. Fortunately, the USGS developed and released the Massachusetts Sustainable-Yield Estimator (MA-SYE) in 2010 (Archfield et al., 2010). According to the source website, the MA-SYE is "a decision-support tool that provides screening-level estimates of the sustainable yield of a basin" (Archfield and USGS, 2010). Sustainable yield is the difference between natural streamflow and the amount of water that must be available to support aquatic habitat and recreational activities.

More precisely, the MA-SYE provides an ArcGIS, Microsoft Excel, and Microsoft Access based tool that can estimate unregulated (i.e., undammed) streamflow values at ungauged, user-defined stream locations in Massachusetts. The MA-SYE provides estimates of mean daily streamflow for the 44-year time period from October 1960 through September 2004. Stream flow values are adjusted to account for “current” water withdrawals and consumption (i.e., water uses documented for the 2000-2004 time period). In addition to downloading and installing the MA-SYE supporting data and ArcGIS extensions from the support website, activation of the Spatial Analyst extension in ArcGIS was required. Permitted groundwater and surface water withdrawal locations had to be requested directly from the MassDEP in order to complete the MA-SYE installation, due to the potentially sensitive nature of the information.

The MA-SYE relies upon a database of long term watershed basin statistics to identify gauged sites that are highly correlated with the ungauged site that the user selects. It develops the regression equations on-the-fly. The user doesn’t actually see the linear regression equations, but is given warnings if the program must operate beyond model limitations. The MA-SYE considers a variety of watershed basin characteristics acquired from statewide data layers when making its reference gauge selection and estimating the flow duration curve for the ungauged site (Brandt, 2010).

Additional modification was necessary to approximate the monthly average of daily mean streamflow values at each of the power plant locations, due to the basin-delineation selection and time period restrictions of the tool. The problem was that the withdrawal and discharge points for each of the facilities are located in tidally-influenced areas, which are generally excluded in the MA-SYE because of tidal effects including additional instream water availability and salinity effects.

The raw output of the MA-SYE is included as Table A5 in the Appendix. Any assumptions or warnings are listed there.

Another issue that had to be remedied was that the MA-SYE does not yet provide flow approximations for months after September 2004.

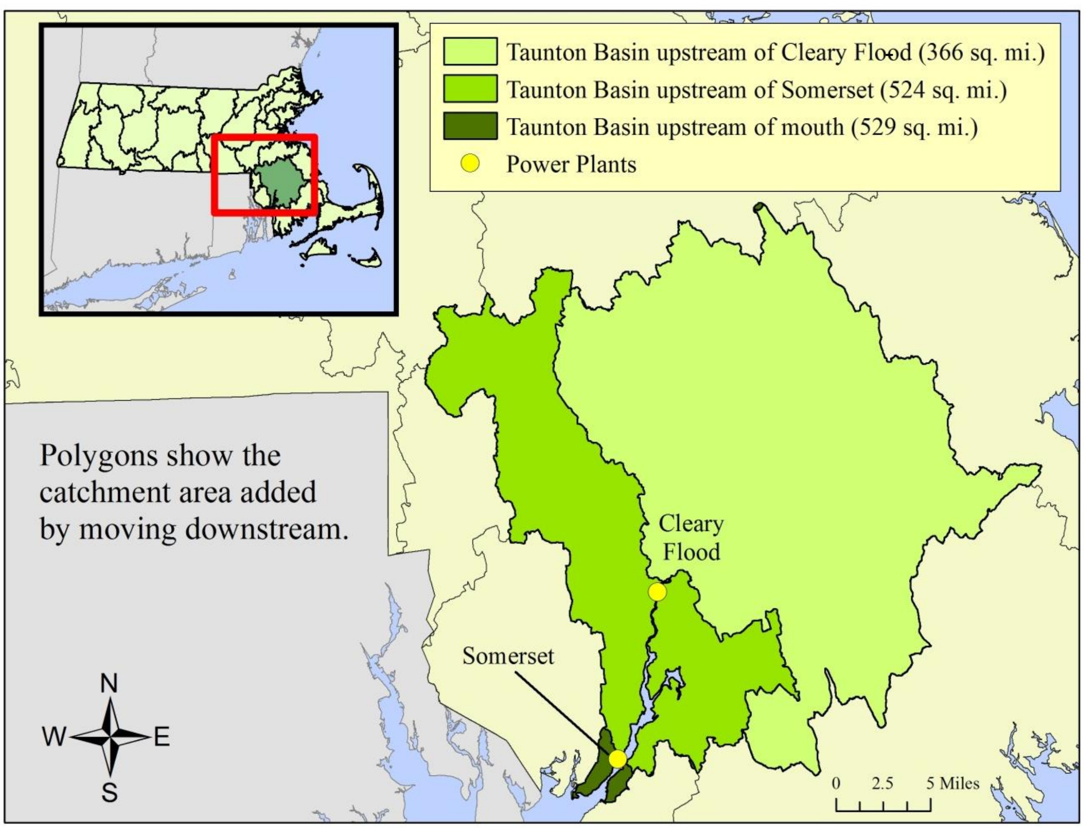
Using streamflow data for the time period October 1960 – September 2004, the MA-SYE identified the Peeptoad Brook gauge (USGS Gauge No. 01115098) at Elmdale Road near Westerly, RI, as the index gauge that was most correlated with the ungauged site slightly upstream of Cleary-Flood. The Taunton River gauge (USGS Gauge No. 01108000) near Bridgewater, MA, was also highly correlated with the ungauged site, but slightly less correlated than the Peeptoad Brook gauge.

Streamflow at Cleary-Flood was approximated by delineating a watershed 1.17 river miles upstream of the facility—a point as far downstream as the MA-SYE would allow. The point is the closest possible location to Cleary-Flood plant that can still be selected for basin delineation in the MA-SYE, and was designated as the Cleary-Flood flow proxy point. There are no major freshwater inputs between the point selected as a proxy for flow at Cleary-Flood and at the real withdrawal/discharge area for Cleary-Flood, so flow at the two locations is expected to be very similar. The area of the contributing basin to the Cleary-Flood flow proxy is 366 square miles. The area of the Taunton River watershed as a whole is 529 square miles (MassGIS, 2003). Flow could not be directly estimated at Somerset station, because the tidally

Table 5. Parameters considered during reference stream gauge selection within the Massachusetts Sustainable-Yield Estimator.

Parameter
Drainage area
Mean basin elevation
Average annual precipitation
Percent of basin that is open water
Average maximum monthly temperature
Percent of basin that is wetlands
Percent of basin that is sand and gravel deposits
Longitude of basin discharge point
Latitude of basin discharge point

Figure 40. Map of cumulative watershed areas within the Taunton River watershed as one moves downstream from Cleary-Flood to the river mouth.



influenced area of the Taunton at the facility is treated as out-of-bounds by the MA-SYE.

Somerset is located 2.7 river miles from the mouth of the Taunton River and Mt. Hope Bay. Massachusetts StreamStats (USGS et al., 2009) allows users to delineate watershed areas anywhere along the length of the Taunton River. The contributing watershed area at a point on the Taunton River next to Somerset was calculated in StreamStats and its area was 524 square miles. The similarity to the total Taunton River watershed area of 529 square miles was expected due to Somerset's proximity to the river mouth.

The drainage basin area-flow ratio equation is used to approximate the fresh water input at Somerset, using the known contributing basin areas and the estimated flow at the Cleary-Flood flow proxy point (Gordon et al., 2004, p. 221):

$$\bar{x}_1 = \bar{x}_2 \frac{A_1}{A_2}$$

Equation 11. Basin area-flow ratio equation (Gordon et al., 2004).

$\bar{x}_1$ is the mean annual flow for the ungauged site, $\bar{x}_2$ is the mean annual flow of the gauged site, A_1 is the area of the ungauged catchment, and A_2 is the area of the gauged catchment. The basin area-flow ratio equation is most accurate for calculating mean annual flow, but is used to approximate mean daily flow for the sites—a point which adds some uncertainty to the flow approximations.

The MA-SYE only provided flow approximations through September 2004, so a different methodology was needed to approximate recent streamflow. For the time period

October 2004 to December 2010, the area-flow ratio method was used again. The reference gauge for approximation was the Taunton River gauge near Bridgewater, MA (USGS Gauge No. 01108000). Using a drainage area of 261 sq mi for the USGS Bridgewater gauge (USGS, 2010), 366 sq mi for the Cleary-Flood flow proxy catchment area, and 524 sq mi for the Somerset Station catchment area, the known daily mean flow values were used to calculate statistics for the two ungauged sites. Before the recent streamflow values were calculated, however, the simplified streamflow model had to be calibrated against (i.e., compared to) MA-SYE values for consistency.

Using the MA-SYE, the average streamflow at Cleary-Flood for the October 1960 to September 2004 time period was estimated to be 672 cfs. Meanwhile, the basin area flow ratio equation that used Bridgewater as the reference gauge yielded an average streamflow of 900 cfs for the October 2004 to December 2010 time period. Similarly, average flow at Somerset for the October 1960 to September 2004 time period was estimated to be 972 cfs, compared to 1,287 cfs for the October 2004 to December 2010 time period. In other words, the streamflow appeared to be substantially different and possibly the result of using an inadequate approximation methodology for the more recent streamflow values. Specifically, the differences may be due to the fact that consumption and diversions along the main stem of the Taunton are unaccounted for when the area-flow ratio method and Bridgewater gauge are used to estimate flow at ungauged sites. Consumption and diversions by water users *are* accounted for in the MA-SYE estimates, so they are lower.

To account for the discrepancy, a scaling factor was introduced to estimate the flows for the 2004-2010 time period. A simple linear regression equation was developed in Microsoft Excel to relate MA-SYE values to the basin area-flow method values at the point 1.17 river miles upstream of Cleary-Flood (i.e., the flow proxy point).

Bridgewater gauge-derived statistics were compared to Peeptoad Brooke gauge-derived data over the 1960-2004 time period available through the MA-SYE. Some years were excluded due to stream gauge inactivity. Specifically, the time periods April 24, 1976 to April 18, 1985 and June 1, 1988 to September 30, 1996 were excluded. The linear regression analysis yielded the following equation:

$$Q_P = 67.52 + 0.848(Q_B)$$

Equation 12. Linear regression model to compare the Peeptoad Brooke river flow gauge data to Bridgewater gauge data.

Q_P is the MA-SYE estimated streamflow in cfs at the Cleary-Flood flow proxy point, based on the Peeptoad Brooke gauge; Q_B is the streamflow at the Bridgewater gauge in cfs. The fit of the model was good, with $R^2 = 0.815$, and the *p*-values for the constant and Q_B both much less than 0.001. The raw summary output from the regression analysis performed in Microsoft Excel to derive Equation 12 is available as Table A6 in the Appendix. Using Equation 12, one can estimate what the MA-SYE *would* produce if it were available for the 2004-2010 time period. The table of estimated Taunton streamflow values for Cleary-Flood and Somerset is available in Table A2 of the Appendix.

That log10-normalization was necessary for the distribution of streamflow in the Taunton River was expected. Indeed, medium-sized unregulated streams often show a pattern of skewness in the positive direction, both because streamflow cannot be less than zero, and because a few extremely heavy flows are to be expected over the course of decades. The lognormal distribution is not perfectly normal, but it is an improvement on the non-normalized distribution.

Box-plots showing daily average streamflow by month show the seasonality of the river. Flow generally peaks during late March and through April as a result of heavier precipitation and thawing ice. The lowest flows tend to occur during the mid- to late-summer months, July, August, and September. Based on the analysis of streamflow patterns presented earlier (Figure 43, Figure 44), it is clear that during the summer months, streamflow tends to be much less variable than during the winter and spring months.

Unsurprisingly, the distribution of average daily freshwater flows of the Taunton River at Somerset is like that of Cleary-Flood, and similarly in need of log10-normalization. The normalized box-plots of flow at Somerset appear to be slightly less varied in range, which may be due to the addition of many tributaries as one moves down stream. In other words, the flow of larger streams tends to be less variable (i.e., less flashy) than that of smaller streams (Brandt, 2010), due to the cumulative effects of flow and the low statistical probability that tributaries will run dry simultaneously. One word of caution about the stream flows at Somerset: streamflow at the station is substantially affected by tidal variation. Mixing with sea water and the physical influence of the salt wedge may positively or negatively influence the rate of freshwater flow past Somerset—

a point that the MA-SYE crafters rightly addressed. Over the course of a day, on average, and in the absence of an extreme coastal weather event, the freshwater input ought to obey the same general hydrological rules of other points in the stream (e.g. water moves downstream).

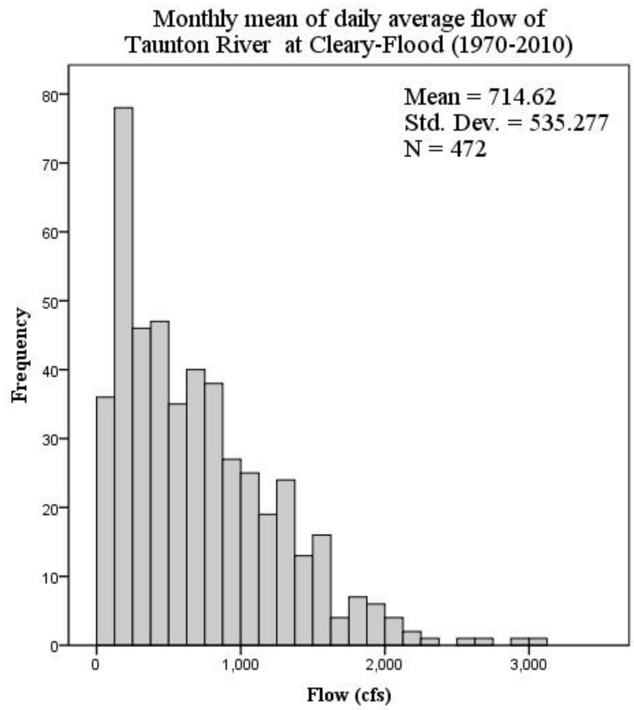
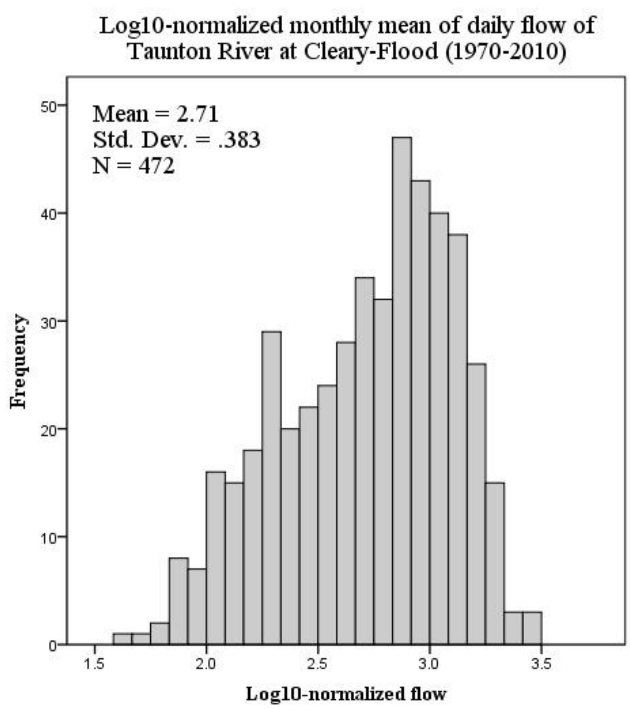


Figure 41. Histogram of estimated streamflow at Cleary-Flood (1970-2010).

Figure 42. Histogram of log10-normalized estimated streamflow at Cleary-Flood (1970-2010).



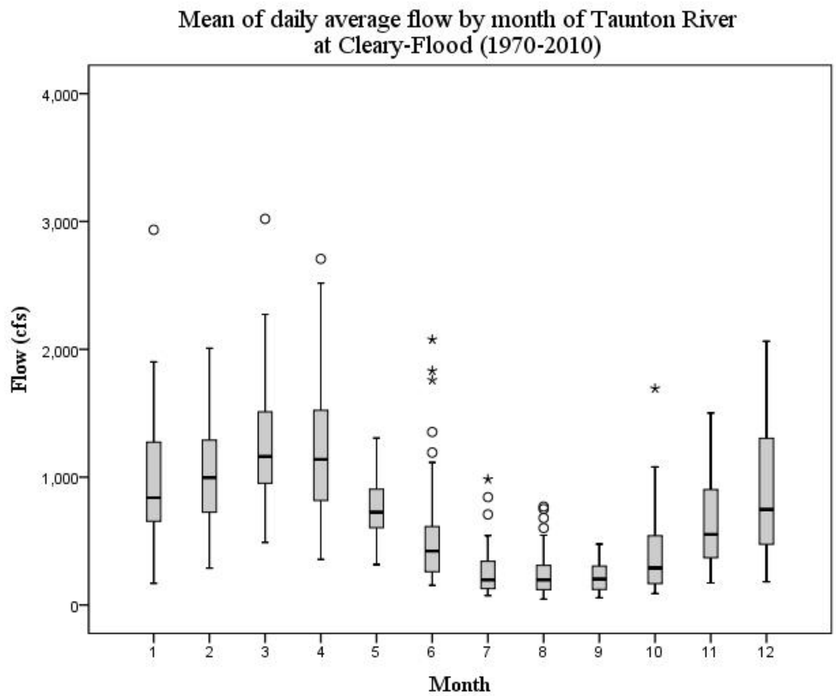
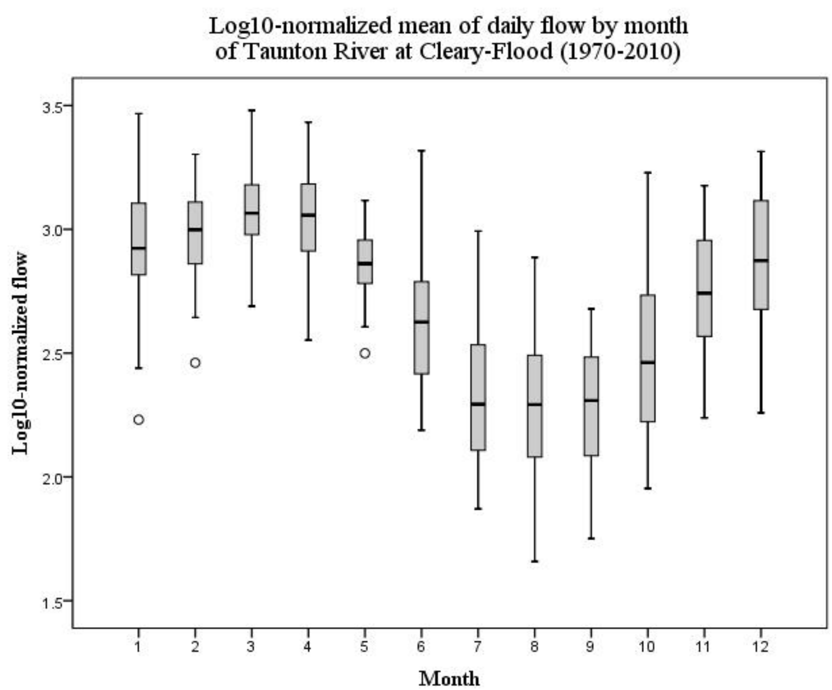


Figure 43. Box-plots of estimated streamflow at Cleary-Flood by month (1970-2010).

Figure 44. Box-plots of log10-normalized estimated streamflow at Cleary-Flood by month (1970-2010).



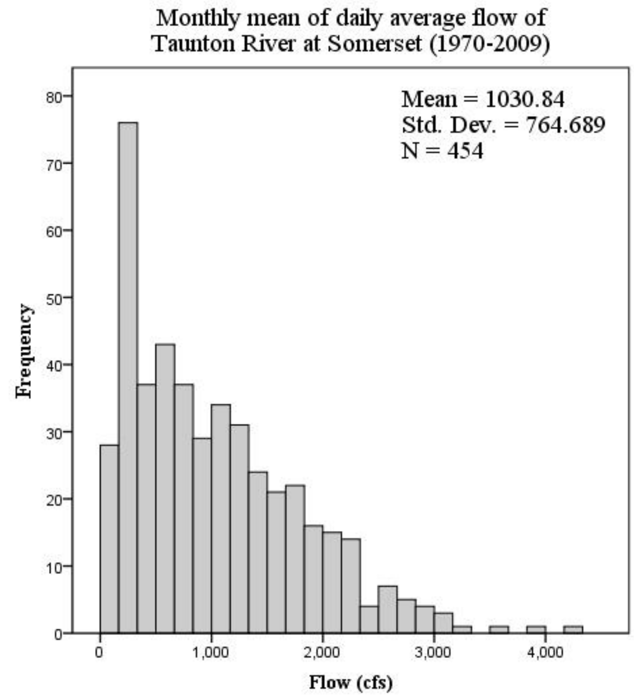
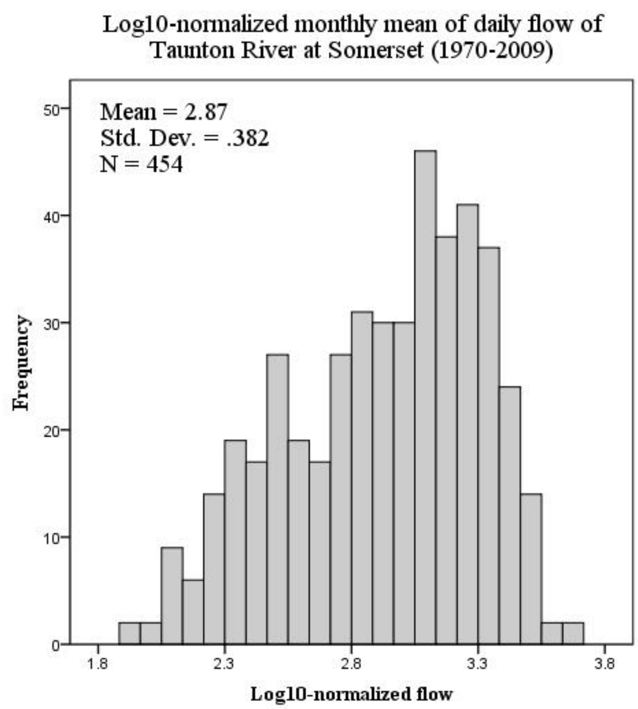


Figure 45. Histogram of estimated streamflow at Somerset (1970-2010).

Figure 46. Histogram of log10-normalized estimated streamflow at Somerset (1970-2010).



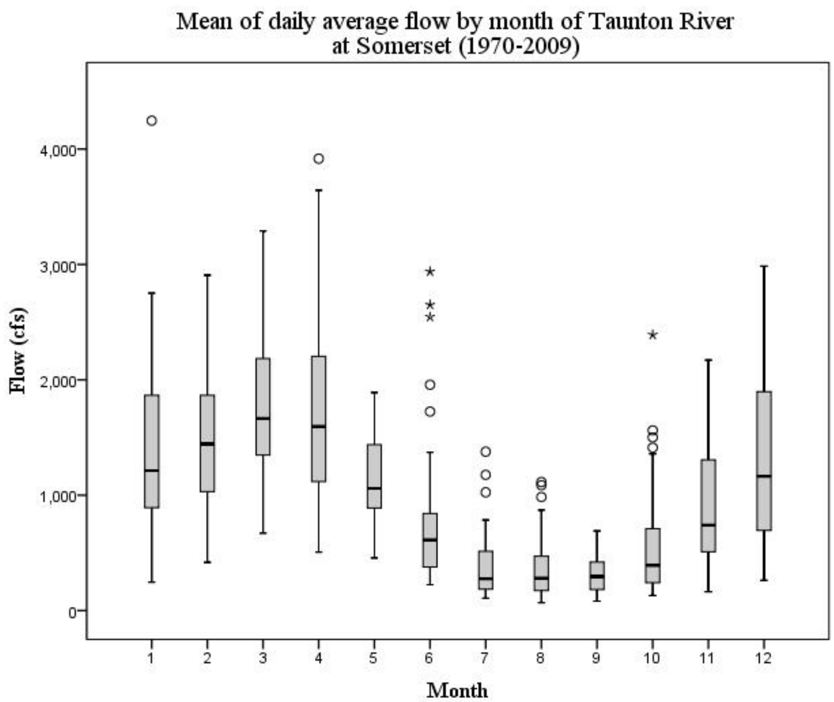
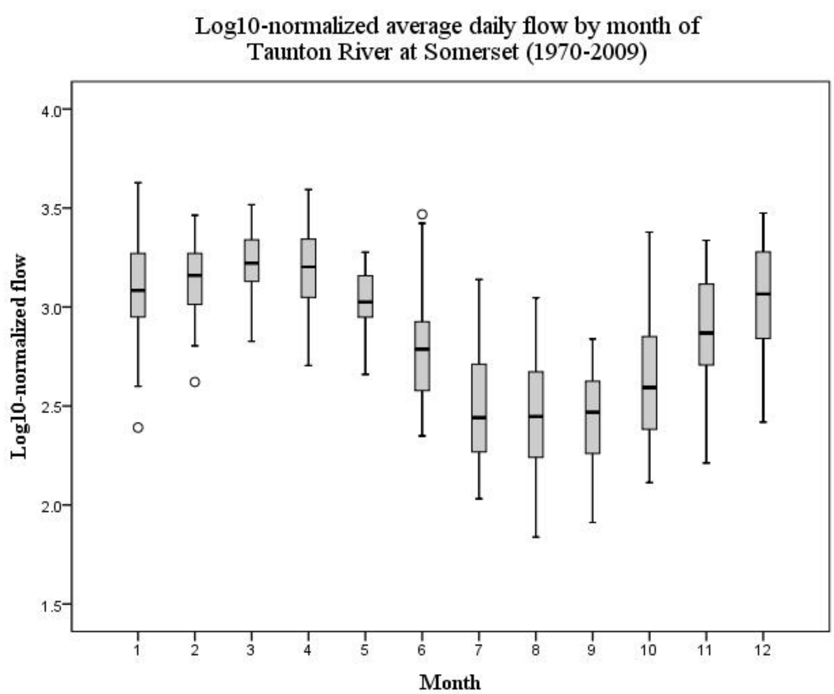


Figure 47. Box-plots of estimated streamflow at Somerset by month (1970-2010).

Figure 48. Box-plots of log10-normalized estimated streamflow at Somerset by month (1970-2010).



Average salinity

The influence of tidal variation in Mt. Hope Bay extends up to 18 miles from the mouth of the Taunton River, with saltwater reaching as far as 12.4 miles upstream (Cantwell et al., 2007). Obviously, saltwater intrusion is an important feature of the river.

In a saltwater-freshwater mixing zone, it stands to reason that ambient water temperatures will respond more rapidly to energy inputs (e.g. solar radiation, conduction with air) than in an area of freshwater where no mixing is occurring, all other things being equal. Sun et al. (2008) confirm that heat capacity is inversely and linearly related to salinity. However, salinity values were excluded from the MLR analysis for several reasons. For one, mixing is very limited at Cleary-Flood, with saltwater influence during low tide being essentially non-existent. More importantly, heat capacity varies only very slightly over the full range of possible salinity values at either site (between 0 and 34 g/kg) (ONR, 2008). The following equation describes the linear relationship between heat capacity and salinity of water at 68 °F (Sun et al., 2008):

$$y = 4.1569 - 0.0044x$$

Equation 13. Equation to relate salinity to heat capacity for water (Sun et al., 2008). y is the heat capacity of water (J/g·K) and x is the salinity (g/kg).

Direct mixing with sea water, tidal backwater effects on stream depth, and water cloudiness are assumed to have a much greater influence on ambient water temperatures at each of the cooling water intakes than changes in salinity.

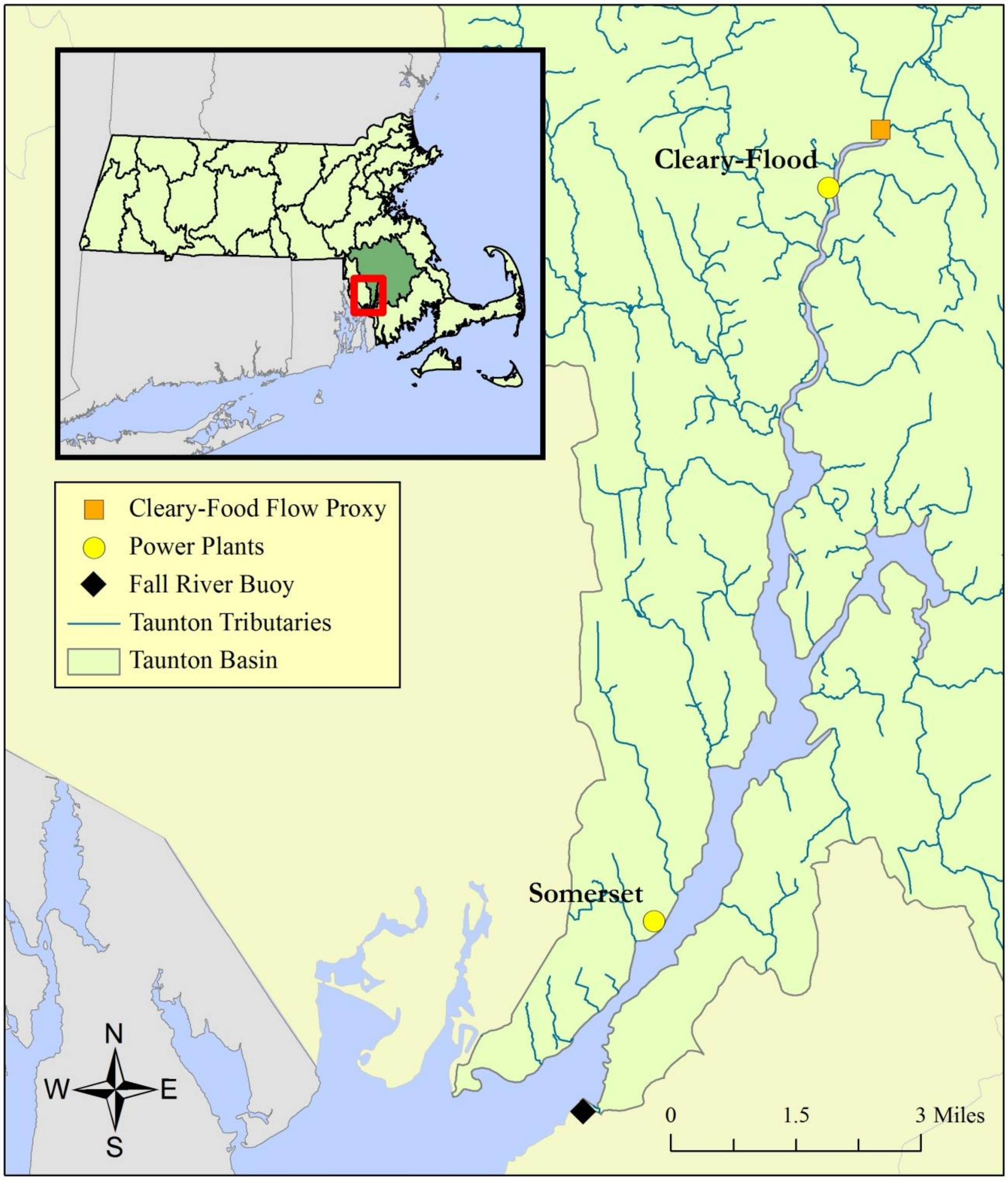
Tidal height

A decrease in water level as a consequence of a low tide may increase water temperatures, especially if the relative input of fresh water is small (U.S. EPA, 2006). During low tide, the influence of ocean water temperature on ambient water temperatures would be at a minimum, while the influence of solar radiation would be at a maximum.

Average daily low tide (i.e., the average of the daily low tide and the daily low low tide) was used to approximate the mean daily low tide. MLLW is the mean low low water level and is used as the datum for the tidal height. The NOAA website from which the tide data was acquired does not specify the precise time period for which the MLLW line applies, or whether the MLLW line is a historical datum that applies for a larger geographic area (NOAA, 2011b).

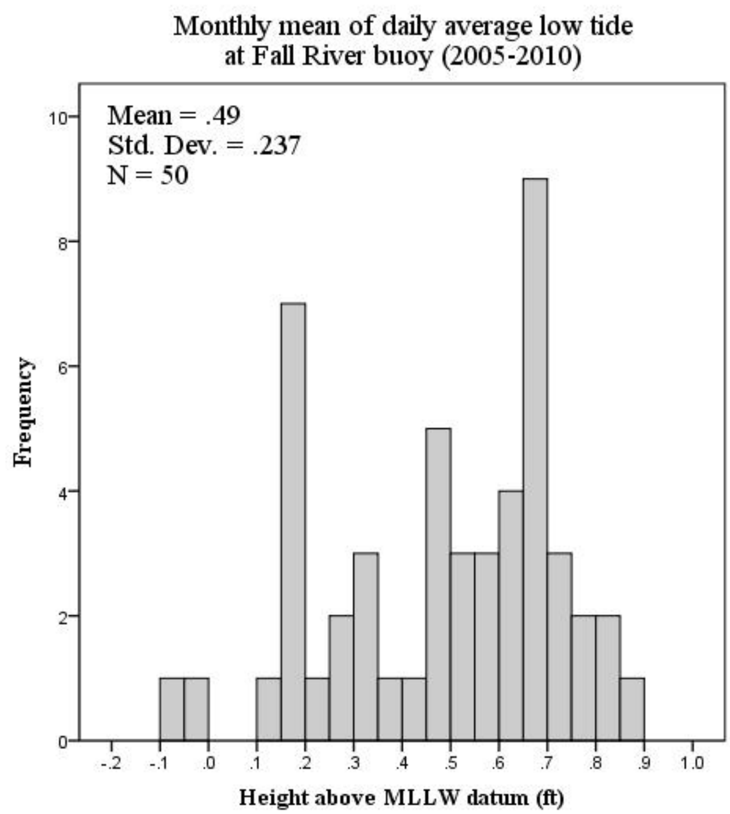
Tide data was taken from the Fall River buoy (Station ID: 8447386), which is maintained by NOAA. The period of available observations for the buoy was October 2005 – December 2010 (NOAA, 2011b). As Figure 49 shows, the Fall River Buoy is located roughly three miles downstream of Somerset generation station, at the southernmost point of the Taunton River watershed.

Figure 49. Map of Fall River buoy tide gauge, Cleary-Flood streamflow proxy, power plants, Taunton River basin, and select Taunton River tributaries.



Tidal height was included in the correlation matrices of both Cleary-Flood and Somerset to capture any possible influences. The use of correlation matrices during regression model development is discussed in a later chapter.

Figure 50. Histogram of average daily low tide height as a deviation from the MLLW for the period 2005-2010 at the Fall River buoy.



Solar radiation

For each month available of each plant's observed water use parameters, an estimation of the total number of sunny days was derived for its potential explanatory value. Theoretical solar irradiance, based on the time of year and the latitude of each of the plants was not used, because it ignores the substantial daily variation of albedo based on cloud cover, and cloudy days are a familiar feature of New England weather. Miller et al. (1992) note the importance of insolation when estimating reservoir water temperature, but they do not explore the issue in their sections on river temperatures at power plants, and instead devote the bulk of the discussion to ambient air temperature and upstream water temperature effects. No high quality data set of insolation values (e.g. hours of direct sunlight during a day) was available for the power plants. However, a rough estimation of the number of sunny days per month was developed using weather observation data from the KMATAUNT6 Weather Station at the Taunton Municipal Airport (Weather Underground, 2011; NCDC, 2011).

An organization called Weather Underground compiles weather data from gauges across the U.S. and does minimal processing to deliver a daily weather report. Sunshine conditions at Taunton Municipal Airport were reported as Sunny (indicated by a graphic of a whole sun), Mostly Sunny (indicated by a graphic of a sun partly covered by a cloud), and Mostly Cloudy (indicated by a graphic of a sun mostly covered by two clouds). In order to develop a proxy for the number of "Sunshine Days" per month, Sunny was given a score of 3, Mostly Sunny a score of 2, and Mostly Cloudy a score of

1. Scores for each month were totaled and divided by three to provide a rough approximation for the amount of solar radiation received by the power plants for each month. All other days, including those which had no data were given a score of zero.

Weather conditions were collected for Cleary-Flood for September 1998 to December 2010, which covered the majority of months reported through the DMRs. Weather conditions were available for Somerset from October 2005 to December 2010, which covered the entire period of record for the available DMR values.

The approach has a number of limitations, and its overall value for the model is questionable. It is unclear from the Weather Underground site and the site for the American Aero Services that have data on the KMATAUNT6 weather station precisely how the sun conditions were established (i.e. direct observation or inferred from rain or fog conditions) (Weather Underground, 2011). The value of sunshine days per month, as calculated, hides serial effects (i.e., many sunshine days in a row) and can only be relied upon for a *very* rough approximation of the total direct solar irradiation that each of the two power plant areas may have received.

A better metric would be minutes or hours of direct sun exposure by a light meter at each site. The distribution of sunny days per month is fairly normal, but the oddly shaped box-plots highlight problems with the data set (e.g. few records for certain months). Ultimately, given the low correlation of sunshine days with the dependent variables and the low quality and reliability of the data available for the sites, it was eliminated from the final MLR analysis, which is illustrated by its appearance in the earliest correlation matrices, but not later ones. In some instances it did correlate with air temperature and other seasonal variables, but only slightly.

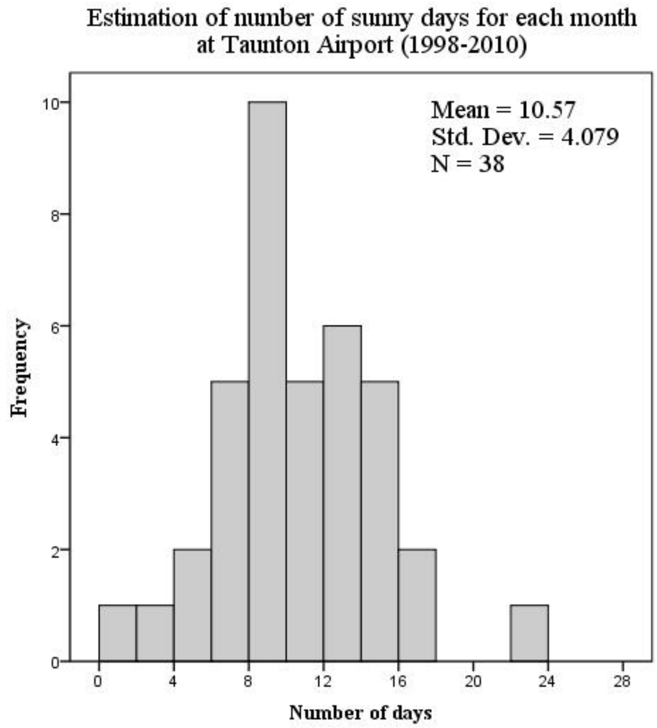
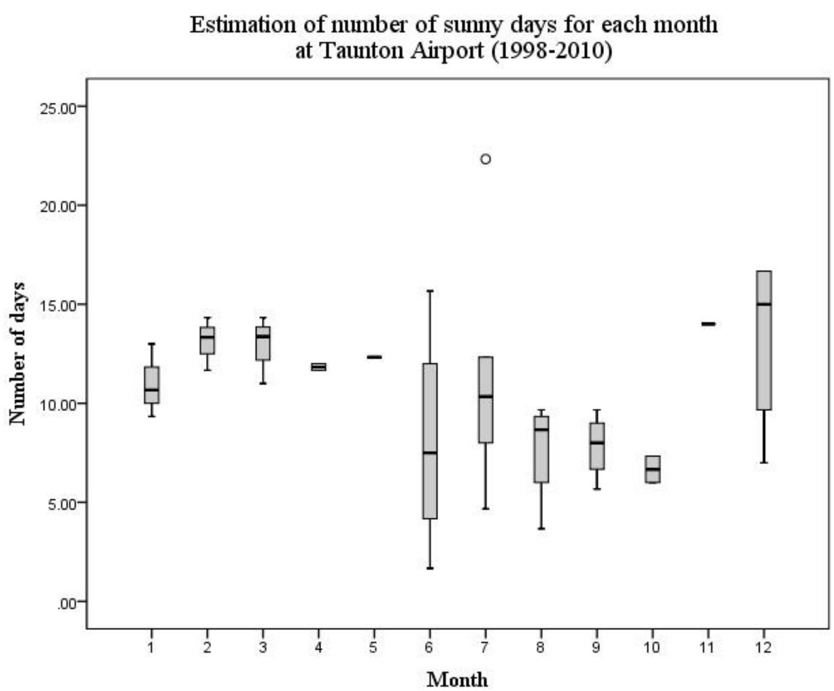


Figure 51. Histogram of sunshine day metric at Taunton Airport for the period 1998-2010.

Figure 52. Box-plots of sunshine day metric by month at Taunton Airport for the period 1998-2010.



Revision of the original model using MLR analysis

The original model, Figure 3 in Chapter 3, lists the major environmental and operational variables that could reasonably be expected to influence cooling water use rates and effluent temperature values. It also shows the NPDES permit-related operational variables as “Secondary Variables,” which vary, as the theory suggests, with environmental variation (e.g. air temperature changes) and operational variation (e.g. electricity generation). It also shows “Undesirable Events” as either a NPDES permit violation or plant dial-back. The “Regulatory Mechanisms” are discussed in later chapters.

The mathematical relationships that each of the parameters has with the other are so multitudinous that a full description of them would be so tedious that it would defeat the original purpose of the model: simplifying some of the staggeringly complex interactions that occur between a power plant and its environment. Before developing the various MLR-based equations, bivariate correlation matrices were used to identify the variables that are most correlated. If two or more variables were found to be highly correlated with both the dependent variable and each other, the variables were tested separately from one another for their explanatory power. For example, it was often the case that streamflow and air temperature were highly correlated with effluent temperature and with each other, so separate equations were developed in which either streamflow *or* air temperature was used to explain the effluent temperature. The correlation between many of the environmental parameters is, in some cases, due to obvious relationships, such as the geometric relationship between streamflow and stream depth, and in other cases is due to much grander phenomena such as differential heating of Earth by the sun.

Another important condition in developing the model was that each NPDES permit-related parameter (e.g. max gross effluent temp, max ΔT, average flow in conduit) was always treated as a dependent variable and *not as an explanatory variable*. The reasoning behind this is that, on one hand, these parameters are often highly correlated with each other, but, on the other hand, the causal relationship between them is easily confused. For example, based on the general equation relating cooling water flow rate, temperature rise of the cooling water, and thermodynamic efficiency (Equation 3), one might conclude that directly altering ΔT would change the cooling water flow rate—one of the more absurd conclusions, but nonetheless representative of the danger of using an equation independently without a view to the order of events. The model is intended to describe at-plant phenomena that occur as a consequence of *outside* forces (e.g. increasing energy demand, heat waves), rather than offering an engineering protocol for how to control which systems in the event of extreme external forces.

Finally, it was not clear at the outset what the precise meaning of a predicted value, such as maximum effluent temperature, would be. When the model predicts that the effluent temperature is 101 °F, given the particular set of inputs, does it mean that the facility necessarily violated its permit? Or that it was forced to dial back its generation? Indeed, with regard to model-generated permit violations, the original model reflects reality somewhat inaccurately. Part of the problem is precipitated by the fact that it is impossible to say, based on the reported data, which days each power plant did have to dial back its generation. Probably, dial back was occurring on days where limitations were exactly reached, but one cannot say for sure.

Hindcasting and forecasting

The meaning of the model output for any given dependent variable depends upon how the model is being used, either for describing the past (i.e., hindcasting) or for predicting the future (i.e., forecasting). In the case of hindcasting, the model generates a value that is consistent with trends in the observed data. For instance, if Somerset reports that the highest instantaneous effluent temperature observed at the power plant for an entire month was 100 °F, one could argue that, based on the amount the power plant generated and the average daily high air temperature observed for the month, there is a high likelihood that the *actual* maximum effluent temperature was greater than 100 °F, and therefore in violation of the permit conditions. At the very least, hindcasting offers a way of estimating what cooling water use rates and temperatures were in the absence of observational data.

In terms of forecasting, the model output can only offer insight into the probability that a power plant operator will be faced with the unpleasant choice of violating the facility permit or dialing back (i.e., the "operational headache" described by Miller et al. (1992)). In the future, those choices will be left up to plant operators—and they usually decide to abide by their permits—but it is incumbent upon environmental regulators and energy-water nexus researchers to try and minimize those situations by using practical foresight.

Model limitations

As with all models, the methodology and resulting regression equations of this research are imperfect. The accuracy of the results are only as good as the quality of the data collected. All of the data used in this research were publically available, and susceptible to the various errors that large, government-funded databases are prone to. A source of anxiety on the part of the author was the reliability of the data sources and whether the methodology of data collection was appropriate for the purposes of the research goals. For the most part, one must rely upon the skill of past researchers—the the countless field researchers who put the datasets together, and past scientists who tried to make sense of similar data sets.

In some instances, the model limitations are quantifiable. For instance, the limitation to drawing conclusions that are relevant *only at the monthly time scale*, is frustrating, but consistent with the way in which NPDES regulations are carried out. A better model would be based on daily at-plant observations and would measure a suite of physical or thermal characteristics at each site to get the fullest picture possible. Furthermore, due to time constraints, only a handful of environmental measures were included as possible explanatory variables. For instance, perhaps daily average temperature, rather than average daily high temperature, is a much better predictor of effluent temperature. That is to say, air temperature can be described in many more ways, and so can things like streamflow, insolation, and so forth.

Additionally, while pumping rate didn't correlate highly with air temperature or energy generation effects, it is clear from the records for each of the power plants that the pumps were run the hardest (i.e., additional pumps were switched on) during the hottest months of the year. This implies that pumping may be an intrinsic part of the multiple linear regression equations used to model each power plant, and so withdrawal rates and temperature rise through the condenser (ΔT) cannot be fully decoupled in the way that they are in later chapters. Without confirmation by the Somerset and Cleary-Flood facility managers, though, it is impossible to describe the methodology that they used to deal with hot weather, among other ambiguities.

Perhaps Brandt (2010) best describes the limitations of model-generated conclusions by noting that errors "arise from numerous sources, including model error, measurement error, and error due to choice of the spatial and temporal scales" (Brandt, 2010, p. 26). The hope is that the biases of the author were kept in check as the data were culled, organized, and deciphered, and that any errors in one direction were compensated for by errors in the other (Wilford, 2001).

CHAPTER 4

RESULTS AND DISCUSSION: PART I

Multiple linear regression equations were developed to individually describe the temperature and water use rate limitations for each of the three outfalls, Cleary-Flood Outfall 001, Cleary-Flood Outfall 002, and Somerset Outfall 007. In all cases, correlation matrices were first generated and analyzed (i.e., an alternative to F-testing) in SPSS to minimize multicollinearity and maximize explanatory power in successive models. Models were generated using the Linear Regression function in SPSS. Correlation matrices and raw model outputs are available in the Appendix.

Except where results were surprisingly good or extraordinarily poor, discussion is limited to a description of the model and does not include conclusions or recommendations, which appear in a later chapter. In a few cases, special modifications had to be made to the data to correct possible reporting errors, and they are discussed. For each model, a summary of the specific input parameters is provided, followed by the associated equation, the R^2 and Standard Error (SE) of the model, and a table that provides specific descriptive values for the constant and coefficients, including the unstandardized coefficient itself, the SE, the standardized coefficient (β), the *t* statistic, and the *p*-value. Summary tables are followed by scatter plot diagrams of observed versus predicted values and auto-fitted trend lines for reference.

The best models for each of the dependent variables were selected for use in hindcasting to identify and highlight months in the past when a limitation is likely to have been exceeded. Table 6 on the following page gives a summary of the equations that were tested. The remainder of the chapter provides a detailed explanation of the methodology used to produce each of the multiple linear regression equations.

Table 6. Regression equation summary

■ Indicates that parameter is part of the regression equation
Light gray = dependent variables
Dark gray = independent variables

*Does not include outliers
†Total generation was used rather than testing units separately

Plant	Outfall	Max. discharge temp. (°F)	Max Δ temp. (F°)	Avg. withdrawal (cfs)	Log_{10} (Avg. withdrawal)	Max. inst. Withdrawal rate (cfs)	Log_{10} (Max. inst. withdrawal)	Air temp. (°F)	Log_{10} (Streamflow) (cfs)	Generation (MWh/month)	Log_{10} (Generation)	Regression Equation	Adj. R^2	Equation no.
CF	001	■						■			■	$T_{max}^{001} = 11.667 + 0.689(A_{CF}) + 6.977(\log_{10} G_{CF})$	.786	(14)
CF	001	■							■		■	$T_{max}^{001} = 129.039 - 24.318(\log_{10} Q_{CF}) + 3.783(\log_{10} G_{CF})$	.375	(15)
CF	001		■					■			■	$\Delta T_{max}^{001} = 8.119 -.123(A_{CF}) + 5.380(\log_{10} G_{CF})$	.262	(16)
CF	001		■						■		■	$T_{max}^{001} = -17.392 + 5.709(\log_{10} Q_{CF}) + 6.244(\log_{10} G_{CF})$	.227	(17)
CF	001			■				■			■	$q_{avg}^{001} = -3.596 +.085(A_{CF}) + 2.781(\log_{10} G_{CF})$	.011	(18)
CF	001				■			■			■	$\log_{10} q_{avg}^{001} = -2.376 +.009(A_{CF}) + .651(\log_{10} G_{CF})$	.079	(19)
CF*	001				■			■			■	$\log_{10} q_{avg}^{001} = -1.076 +.006(A_{CF}) + .292(\log_{10} G_{CF})$	.165	(20)
CF	001					■		■			■	$q_{max}^{001} = -22.407 +.297(A_{CF}) + 10.003(\log_{10} G_{CF})$	.350	(21)
CF	002	■						■			■	$T_{max}^{002} = 62.008 +.282(A_{CF}) + 2.314(\log_{10} G_{CF})$	.213	(22)
CF†	002	■						■				$T_{max}^{002} = 67.975 +.310(A_{CF})$	.205	(23)
CF	002			■							■	$\log_{10} q_{avg}^{002} = -1.215 + .071(\log_{10} G_{CF}^{U8}) + .054(\log_{10} G_{CF}^{U9})$	.213	(24)
CF	002						■	■			■	$\log_{10} q_{max}^{002} = -1.238 + .006(A_{CF}) + .052(\log_{10} G_{CF}^{U8}) + .058(\log_{10} G_{CF}^{U9})$	.227	(25)
S	007	■						■		■		$T_{max}^{007} = 26.178 +.830(A_S) + .0001(G_S)$	.901	(26)
S	007	■							■	■		$T_{max}^{007} = 26.178 +.830(\log_{10} Q_S) + .0001(G_S)$	.355	(27)
S	007		■					■		■		$\Delta T_{max}^{007} = 21.903 - .033(A_S) + .00003(G_S)$	.095	(28)
S	007			■				■		■		$q_{avg}^{007} = 79.438 +.272(A_S) + .001(G_S)$	.540	(29)
S	007			■					■	■		$q_{avg}^{007} = 125.572 - 9.801(\log_{10} Q_S) + .001(G_S)$	.196	(31)

Cleary-Flood Outfall 001

Temperature limitations

Two parameters are regulated at Cleary-Flood Outfall 001: maximum instantaneous discharge temperature and maximum temperature rise between the intake and the outfall (ΔT).

A model to predict the monthly maximum instantaneous effluent temperature at Cleary-Flood Outfall 001 using monthly mean of daily high air temperature and log10-normalized monthly net electricity generation as explanatory variables is described with the following equation:

$$T_{max}^{001} = 11.667 + 0.689(A_{CF}) + 6.977(\log_{10} G_{CF})$$

Equation 14. Equation to relate maximum instantaneous effluent temperature to monthly mean of daily high air temperature and log10-normalized monthly net electricity generation at Cleary-Flood Outfall 001.

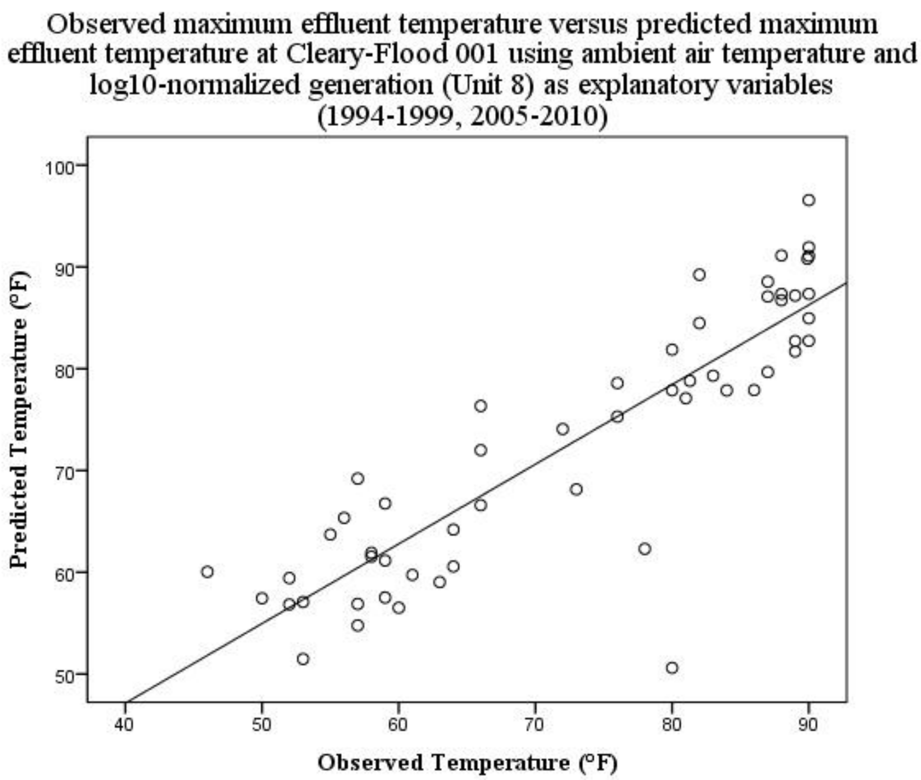
T_{max}^{001} is maximum instantaneous effluent temperature in °F, A_{CF} is monthly mean of daily high air temperature in °F, and G_{CF} is monthly net electricity generation in MWh. The model described 78.6 percent of the variation in the dependent variable (Adj. R^2 = .786) and had a Standard Error (SE) of 6.604.

Table 7. Coefficient summary for model relating maximum instantaneous effluent temperature to monthly mean of daily high air temperature and log10-normalized monthly net electricity generation at Cleary-Flood Outfall 001.

	Coeff.	SE	β	t	*p*-value
(Constant)	11.667	6.911		1.688	.097
A_{CF}	.689	.050	.869	13.798	< .001
$\log_{10}G_{CF}$	6.977	.310	.190	3.020	.004

The raw SPSS model output is available as Table A8 in the Appendix.

Figure 53. Scatter plot of observed max effluent temperature versus predicted max effluent temperature at Cleary-Flood Outfall 001, where ambient air temperature and log10-normalized generation are explanatory variables.



A model to predict the monthly maximum instantaneous effluent temperature at Cleary-Flood Outfall 001 using log10-normalized monthly average of daily mean streamflow and log10-normalized monthly net electricity generation as explanatory variables is described with the following equation:

$$T_{max}^{001} = 129.039 - 24.318(\log_{10} Q_{CF}) + 3.783(\log_{10} G_{CF})$$

Equation 15. Equation to relate maximum instantaneous effluent temperature to log10-normalized monthly average of daily mean streamflow and log10-normalized monthly net electricity generation at Cleary-Flood Outfall 001.

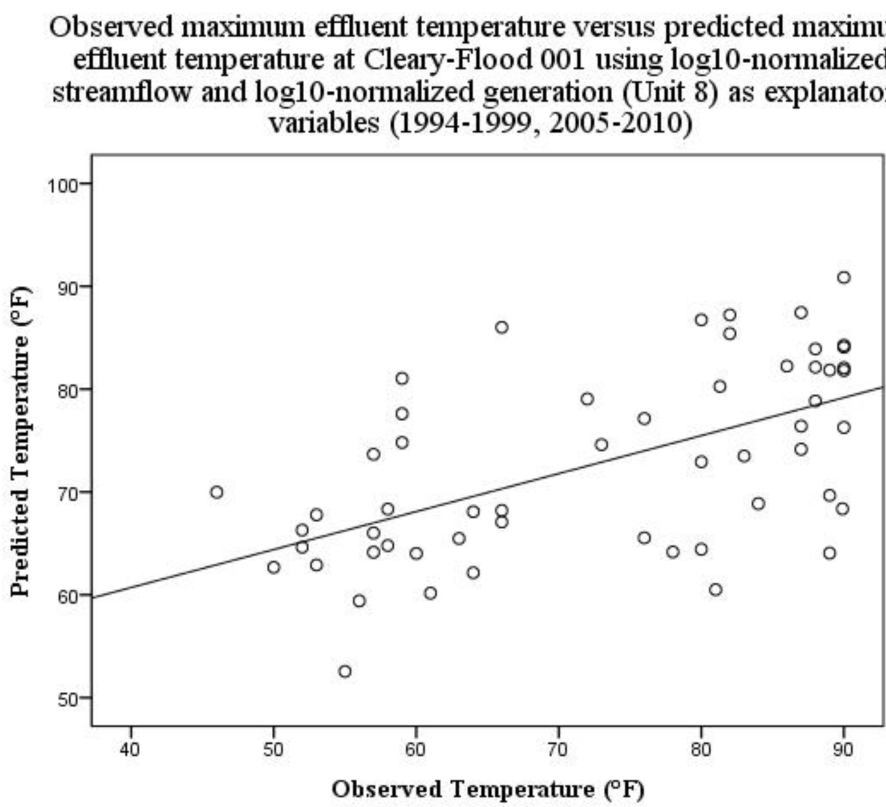
T_{max}^{001} is maximum instantaneous effluent temperature in °F, Q_{CF} is monthly average of daily mean streamflow of the Taunton River at Cleary-Flood in cfs, and G_{CF} is monthly net electricity generation in MWh. The model described only 37.5 percent of the variation in the dependent variable (Adj. R^2 = .375) and had a Standard Error (SE) of 11.290.

Table 8. Coefficient summary for model relating maximum instantaneous effluent temperature to log10-normalized monthly average of daily mean streamflow and log10-normalized monthly net electricity generation at Cleary-Flood Outfall 001.

	Coeff.	SE	β	t	*p*-value
(Constant)	129.039	17.247		7.482	< .001
$\log_{10}Q_{CF}$	-24.318	4.372	-.606	-5.563	< .001
$\log_{10}G_{CF}$	3.783	3.999	.103	.946	.348

The raw SPSS model output is available as Table A9 in the Appendix.

Figure 54. Scatter plot of observed max effluent temperature versus predicted max effluent temperature at Cleary-Flood Outfall 001, where log10-normalized streamflow and log10-normalized generation are explanatory variables.



A model to predict the monthly maximum instantaneous ΔT of cooling water at Cleary-Flood Outfall 001 using monthly mean of daily high air temperature and log10-normalized monthly net electricity generation as explanatory variables is described with the following equation:

$$\Delta T_{max}^{001} = 8.119 - .123(A_{CF}) + 5.380(\log_{10} G_{CF})$$

Equation 16. Equation to relate maximum instantaneous ΔT of cooling water to monthly mean of daily high air temperature and log10-normalized monthly net electricity generation at Cleary-Flood Outfall 001

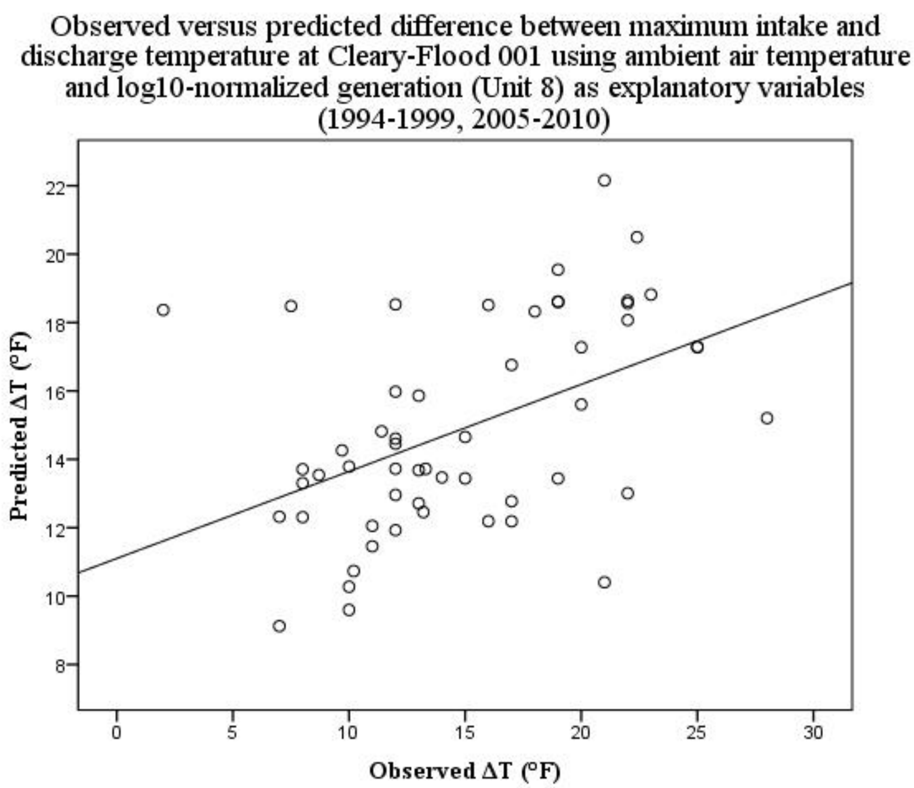
T_{max}^{001} is maximum instantaneous difference between discharge and intake temperatures for cooling water in F°, A_{CF} is monthly mean of daily high air temperature in °F, and G_{CF} is monthly net electricity generation in MWh. The model described only 26.2 percent of the variation in the dependent variable (Adj. R^2 = .262) and had a Standard Error (SE) of 4.843.

Table 9. Coefficient summary for model relating maximum instantaneous ΔT of cooling water to monthly mean of daily high air temperature and log10-normalized monthly net electricity generation at Cleary-Flood Outfall 001.

	Coeff.	SE	β	t	*p*-value
(Constant)	8.119	5.092		1.594	.117
A_{CF}	-.123	.037	-.396	-3.354	.002
$\log_{10}G_{CF}$	5.380	1.706	.372	3.153	.003

The raw SPSS model output is available as Table A11 in the Appendix.

Figure 55. Scatter plot of observed max ΔT versus predicted max ΔT at Cleary-Flood Outfall 001, where monthly mean of daily high air temperature and log10-normalized generation are explanatory variables.



A model to predict the monthly maximum instantaneous ΔT of cooling water at Cleary-Flood Outfall 001 using log10-normalized monthly average of daily mean streamflow and log10-normalized monthly net electricity generation as explanatory variables is described with the following equation:

$$\Delta T_{max}^{001} = -17.392 + 5.709(\log_{10} Q_{CF}) + 6.244(\log_{10} G_{CF})$$

Equation 17. Equation to relate maximum instantaneous ΔT of cooling water to log10-normalized monthly average of daily mean streamflow and log10-normalized monthly net electricity generation at Cleary-Flood Outfall 001.

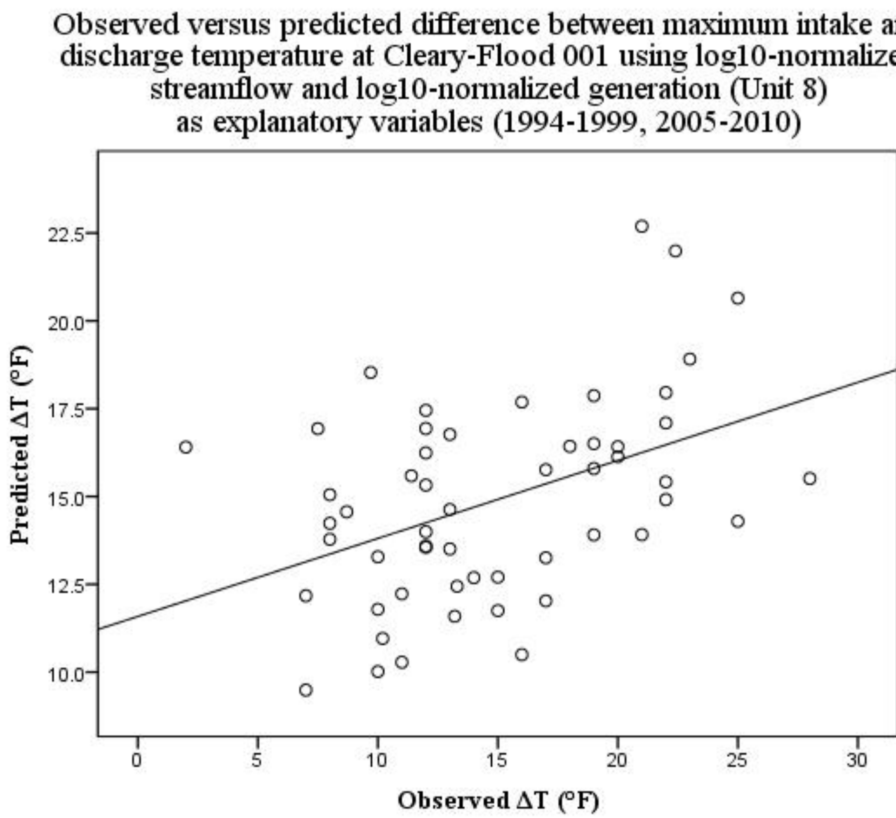
ΔT_{max}^{001} is maximum instantaneous difference between discharge and intake temperatures for cooling water in F°, Q_{CF} is monthly average of daily mean streamflow of the Taunton River at Cleary-Flood in cfs, and G_{CF} is monthly net electricity generation in MWh. The model described only 22.7 percent of the variation in the dependent variable (Adj. R^2 = .227) and had a Standard Error (SE) of 4.959.

Table 10. Coefficient summary for model relating maximum instantaneous ΔT of cooling water to log10-normalized monthly average of daily mean streamflow and log10-normalized monthly net electricity generation at Cleary-Flood Outfall 001.

	Coeff.	SE	β	t	*p*-value
(Constant)	-17.392	7.847		-2.216	.031
$\log_{10}Q_{CF}$	5.709	1.971	.356	2.896	.006
$\log_{10}G_{CF}$	6.244	1.778	.432	3.512	.001

The raw SPSS model output is available as Table A12 in the Appendix.

Figure 56. Scatter plot of observed max ΔT versus predicted max ΔT at Cleary-Flood Outfall 001, where log10-normalized streamflow and log10-normalized generation are explanatory variables.



Water use rate limitations

Two cooling water flow parameters were regulated at Cleary-Flood Outfall 001: monthly average rate of withdrawal (i.e. flow through conduit, rate of water use, flow at outfall) and maximum instantaneous flow.

A model to predict the monthly average rate of withdrawal at Cleary-Flood Outfall 001 using monthly mean of daily high air temperature and log10-normalized monthly net electricity generation as explanatory variables is described with the following equation:

$$q_{avg}^{001} = -3.596 + .085(A_{CF}) + 2.781(\log_{10} G_{CF})$$

Equation 18. Equation to relate monthly average withdrawal rate of cooling water to monthly mean of daily high air temperature and log10-normalized monthly net electricity generation at Cleary-Flood Outfall 001.

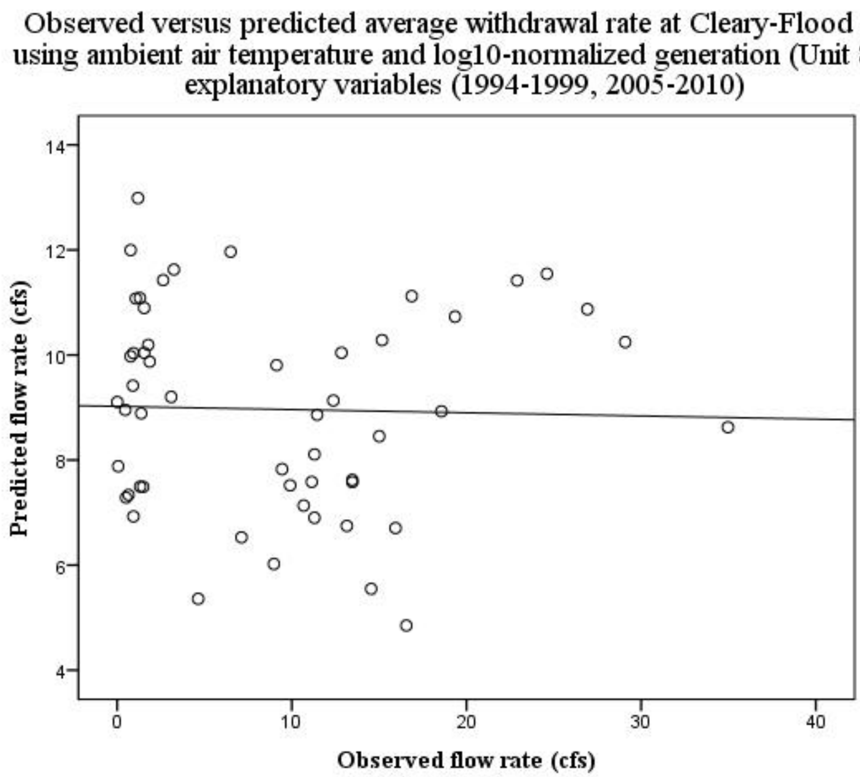
q_{avg}^{001} is monthly average withdrawal in cfs, A_{CF} is monthly mean of daily high air temperature in °F, and G_{CF} is monthly net electricity generation in MWh. The model described a scant 1.1 percent of the variation in the dependent variable (Adj. R^2 = .011) and had a Standard Error (SE) of 8.535.

Table 11. Coefficient summary for model relating monthly average rate of withdrawal to monthly mean of daily high air temperature and log10-normalized monthly net electricity generation at Cleary-Flood Outfall 001.

	Coeff.	SE	β	t	*p*-value
(Constant)	-3.596	9.232		-.389	.699
A_{CF}	.085	.065	.178	1.291	.203
$\log_{10}G_{CF}$	2.781	3.210	.120	.866	.390

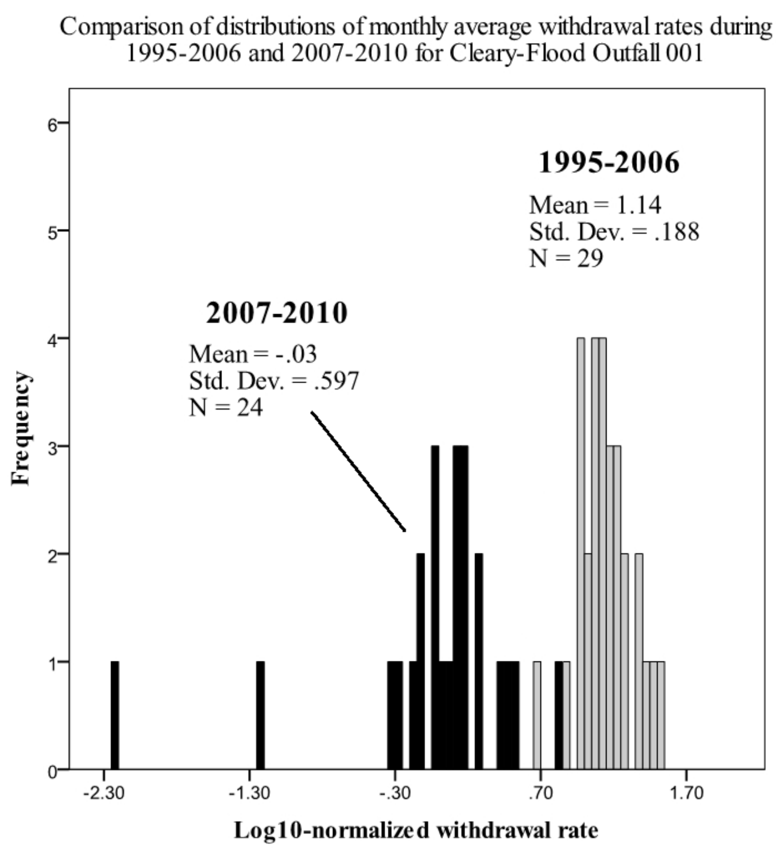
The raw SPSS model output is available as Table A14 in the Appendix.

Figure 57. Scatter plot of observed monthly average rate of withdrawal versus predicted monthly average rate of withdrawal at Cleary-Flood Outfall 001, where ambient air temperature and log10-normalized generation are explanatory variables.



Given the skewness of the untransformed distribution of average cooling water flow rates for Cleary-Flood Outfall 001 and the relatively normal distribution of the log10-transformed distribution of flow rates, the model was tested for its ability to predict log10-normalized rates, rather than untransformed rates. Furthermore, due largely to permit changes in 2006, average flow dropped precipitously. The average monthly withdrawal rate for the period 1994-2006 was 15.20 cfs (n = 29), while the average monthly withdrawal rate for the period 2007-2010 was only 1.50 cfs (n = 24). The following histogram illustrates this difference.

Figure 58. Comparison of distributions of log10-normalized withdrawal rates (i.e. flow in conduit) for Cleary-Flood Outfall 001 during two time periods, 1995-2006 vs. 2007-2010.



The close reader may notice that the shape of the histogram is similar to the peak and valley character of an earlier histogram for the same outfall, specifically Figure 9, which shows maximum instantaneous discharge temperatures. In that case, however, another look at the temperature data revealed that grouping was not caused by permit changes after 2006, but was likely due to the seasonal variation of both air temperature and electricity demand (i.e., electricity generation)

Side-by-side comparison of flow values from the two permit periods also revealed two possible outliers at $\mathbf{log}_{10} q_{avg}^{001}$ = -1.21 and $\log_{10} q_{avg}^{001}$ = -2.21. A modified multiple linear regression analysis was performed with and without the outliers (Equation 19 and Equation 20, respectively).

The modified model to predict the monthly average rate of withdrawal (i.e., flow through conduit) at Cleary-Flood Outfall 001 using monthly mean of daily high air temperature and log10-normalized monthly net electricity generation as explanatory variables is described with the following two equations and summarized by the following two tables:

$$\log_{10} q_{avg}^{001} = -2.376 + .009(A_{CF}) + .651(\log_{10} G_{CF})$$

Equation 19. Equation to relate log10-normalized monthly average withdrawal rate of cooling water to monthly mean of daily high air temperature and log10-normalized monthly net electricity generation at Cleary-Flood Outfall 001 for the period 2007-2010, including possible outliers.

$$\log_{10} q_{avg}^{001} = -1.076 + .006(A_{CF}) + .292(\log_{10} G_{CF})$$

Equation 20. Equation to relate log10-normalized monthly average withdrawal rate of cooling water to monthly mean of daily high air temperature and log10-normalized monthly net electricity generation at Cleary-Flood Outfall 001 for the period 2007-2010, excluding possible outliers.

Table 12. Coefficient summary for model relating monthly average rate of withdrawal to monthly mean of daily high air temperature and log10-normalized monthly net electricity generation at Cleary-Flood Outfall 001 for the period 2007-2010, including possible outliers.

	Coeff.	SE	β	t	*p*-value
(Constant)	-2.376	1.224		-1.942	.066
A_{CF}	.009	.007	.291	1.430	.167
$\log_{10}G_{CF}$	.651	.400	.331	1.627	.119

Table 13. Coefficient summary for model relating monthly average rate of withdrawal to monthly mean of daily high air temperature and log10-normalized monthly net electricity generation at Cleary-Flood Outfall 001 for the period 2007-2010, excluding possible outliers.

	Coeff.	SE	β	t	*p*-value
(Constant)	-1.076	.551		-1.951	.066
A_{CF}	.006	.003	.429	2.120	.047
$\log_{10}G_{CF}$	.292	.180	.329	1.626	.120

q_{avg}^{001} is monthly average withdrawal in cfs, A_{CF} is monthly mean of daily high air temperature in °F, and G_{CF} is monthly net electricity generation in MWh. The model that included outliers, Equation 19, described only 7.9 percent of the variation in the dependent variable (Adj. R^2 = .079) and had an SE of .573. The model that did not include the two outliers, Equation 20, was only a slight improvement, describing a mere 16.5 percent of the variation in the dependent variable (Adj. R^2 = .165) and having an SE of .250.

The raw SPSS model output for each equation is available as Table A16 and Table A17, respectively, in the Appendix.

The maximum instantaneous rate of flow through Cleary-Flood Outfall 001 was also a parameter of interest. A model to predict the monthly maximum instantaneous rate of withdrawal (i.e., flow through conduit) at Cleary-Flood Outfall 001 using monthly mean of daily high air temperature and log10-normalized monthly net electricity generation as explanatory variables may be described by the following equation:

$$q_{max}^{001} = -22.407 + .297(A_{CF}) + 10.003(\log_{10} G_{CF})$$

Equation 21. Equation to relate maximum instantaneous rate of withdrawal to monthly mean of daily high air temperature and log10-normalized monthly net electricity generation at Cleary-Flood Outfall 001.

q_{max}^{001} is monthly maximum instantaneous withdrawal in cfs, A_{CF} is monthly mean of daily high air temperature in °F, and G_{CF} is monthly net electricity generation in MWh. The model described 35.0 percent of the variation in the dependent variable (Adj. R^2 = .350) and had an SE of 8.760.

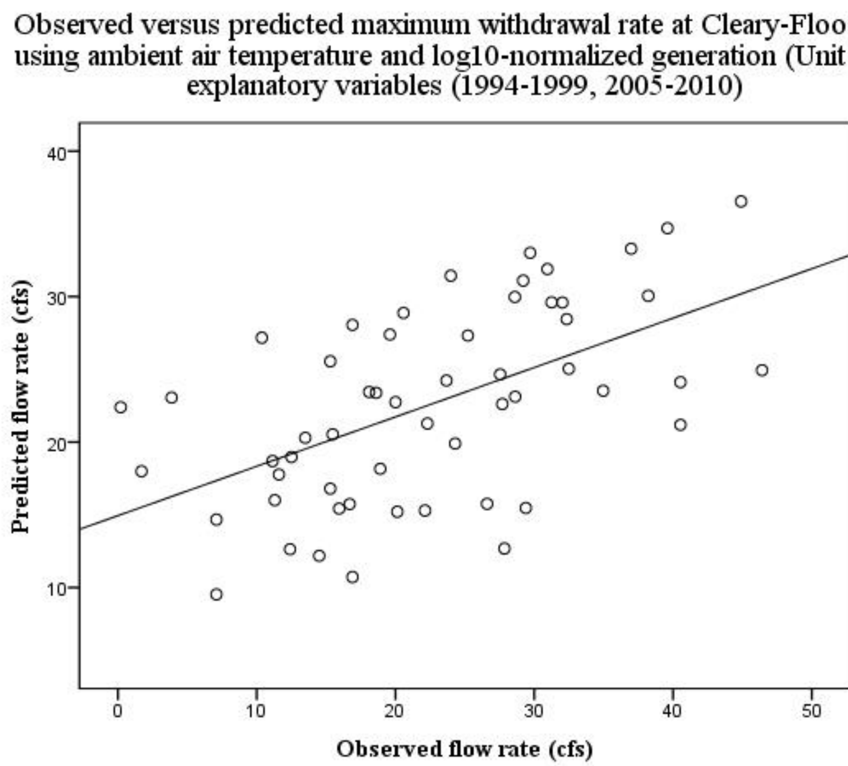
An additional MLR was performed using log10-normalized streamflow at Cleary-Flood and log10-normalized net electricity generation as explanatory variables, yielding an equation (not shown) that explained only 16.6 percent of the variation in the dependent variable (Adj. R^2 = .166) and had an SE of 9.926. The raw SPSS output for that MLR model is available as Table A20 in the Appendix.

Table 14. Coefficient summary for model relating monthly maximum instantaneous rate of withdrawal to monthly mean of daily high air temperature and log10-normalized monthly net electricity generation at Cleary-Flood Outfall 001.

	Coeff.	SE	β	t	*p*-value
(Constant)	-22.407	9.167		-2.444	.018
A_{CF}	.297	.066	.492	4.489	>.001
$\log_{10}G_{CF}$	10.003	3.064	.358	3.264	.002

The raw SPSS model output is available as Table A19 in the Appendix.

Figure 59. Scatter plot of observed monthly maximum instantaneous rate of withdrawal versus predicted monthly maximum instantaneous rate of withdrawal at Cleary-Flood Outfall 001, where ambient air temperature and log10-normalized generation are explanatory variables.



Hindcasting

The models with the highest adjusted R^2 values for each of the dependent variables of interest were used to estimate past cooling water flow rates and effluent temperatures based on historical values for the explanatory values (e.g. air temperature, monthly energy generation).

Interestingly, the model with the best predictive power—used to estimate maximum instantaneous discharge temperature—was also the only one to reveal possible violations. There are only two alleged violations on record for Cleary-Flood Outfall 001, and both are for ΔT values in excess of 23 F° degrees. The alleged violations occurred in December 2008 (28 F°) and December 2010 (25 F°). The model estimated ΔT for those two months to be 15.7 F° and 17.7 F°, respectively. The discrepancy is likely due to the heavy influence of ambient air temperatures on the estimation, which are very low in Massachusetts during the wintertime. Given the apparent reliability of the maximum instantaneous effluent temperature model, and given the number of instances where the limitation was exceeded, it seems *extremely likely* that additional temperature-related violations have occurred.

Admittedly, the models for estimating flow rates were generally weaker than the temperature models. However, it is noteworthy that the highest ever estimated log10-normalized average flow rate for a single month over the 1978-2010 time period was 0.5917, corresponding to a flow rate of 3.91 cfs; the limit at the time was 1.7860, corresponding to a flow rate of 61.1 cfs. The limit was later changed to 8.97 cfs, which is still more than twice as high as the highest monthly average flow rate ever recorded. Similarly, the highest ever estimated maximum flow rate for a single month over the 1978-2010 was 42.61 cfs, and it happened to occur during the same month, August 2005. The max effluent limit at the time was, and remains, 61.1 cfs.

Table 15. Hindcasting results for Cleary-Flood Outfall 001, showing observed and predicted values (1978-2010).

Year	Month	Max Temp, Predicted (°F)	Max Temp, Observed (°F)	Permit Limit (°F)
1979	7	94.7	NR	90
1980	6	90.2	NR	90
1980	7	94.3	NR	90
1980	8	92.9	NR	90
1981	7	91.0	NR	90
1982	7	90.2	NR	90
1983	7	92.1	NR	90
1983	8	91.8	NR	90
1984	6	90.5	NR	90
1984	8	92.5	NR	90
1986	7	90.9	NR	90
1987	7	91.0	NR	90
1988	7	92.2	NR	90
1988	8	94.6	NR	90
1990	7	90.5	NR	90
1990	8	91.9	NR	90
1991	7	90.6	NR	90
1991	8	93.0	NR	90
1993	7	91.2	NR	90
1993	8	92.2	NR	90
1994	7	93.6	NR	90
1995	7	92.4	NR	90
1995	8	91.3	NR	90
1997	7	92.3	NR	90
1998	7	92.7	NR	90
1998	8	92.1	NR	90
1999	6	91.8	90	90
1999	7	95.8	90	90
2003	7	92.2	NR	90
2003	8	93.9	NR	90
2005	6	93.9	NR	90
2005	7	96.8	NR	90
2005	8	98.5	NR	90
2005	9	91.9	NR	90
2006	7	90.8	90	90
2007	7	90.9	88	90
2010	7	91.0	90	90

Estimated number of violations over 1978-2010 time period = 37.
Number of violations on record = 2 (for ΔT, not max. temp.).
NR means not recorded at the MassDEP SERO or in the ECHO database.

Cleary-Flood Outfall 002

Temperature limitation

One temperature parameter is regulated at Cleary-Flood Outfall 002: maximum instantaneous discharge temperature. Maximum temperature rise between the intake and the outfall (ΔT) is not regulated.

A model to predict the monthly maximum instantaneous effluent temperature at Cleary-Flood Outfall 002 using monthly mean of daily high air temperature and log10-normalized total net monthly electricity generation as explanatory variables is described with the following equation:

$$T_{max}^{002} = 62.008 + .282(A_{CF}) + 2.314(\log_{10} G_{CF})$$

Equation 22. Equation to relate maximum instantaneous effluent temperature to monthly mean of daily high air temperature and log10-normalized total net monthly electricity generation at Cleary-Flood Outfall 002.

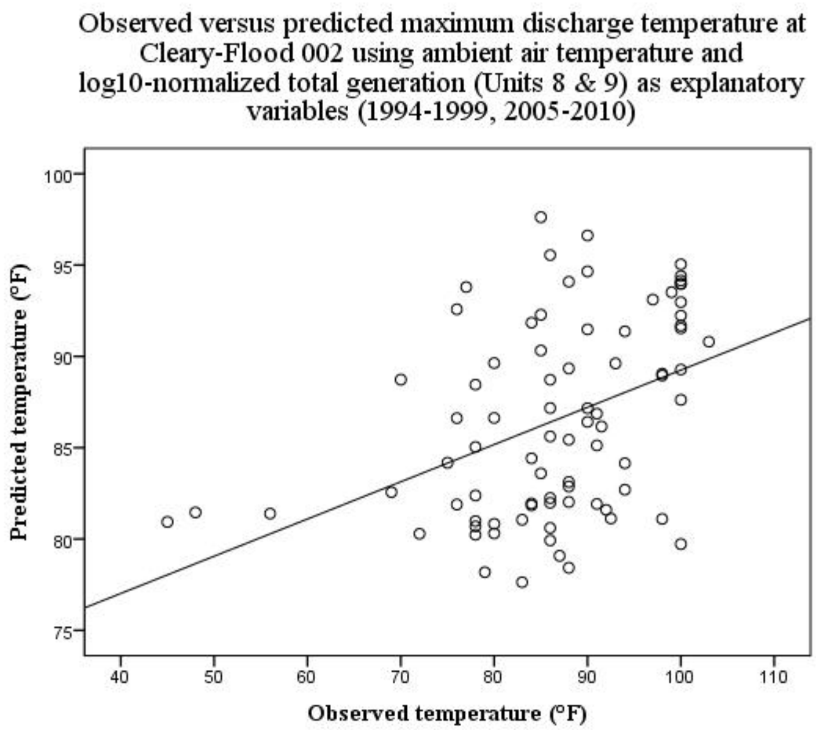
T_{max}^{002} is maximum instantaneous effluent temperature in °F, A_{CF} is monthly mean of daily high air temperature in °F, and G_{CF} is total net monthly electricity generation in MWh. The model described only 21.3 percent of the variation in the dependent variable (Adj. R^2 = .213) and had an SE of 9.796.

Table 16. Coefficient summary for model relating maximum instantaneous effluent temperature to monthly mean of daily high air temperature and log10-normalized total net monthly electricity generation at Cleary-Flood Outfall 002.

	Coeff.	SE	β	t	*p*-value
(Constant)	62.008	6.062		10.228	< .001
A_{CF}	2.82	.069	.424	4.084	< .001
$\log_{10}G_{CF}$	2.314	1.730	.139	1.338	.185

The raw SPSS model output is available as Table A22 in the Appendix.

Figure 60. Scatter plot of observed max effluent temperature versus predicted max effluent temperature at Cleary-Flood Outfall 002, where ambient air temperature and log10-normalized generation are explanatory variables.



An additional MLR was performed using *only* monthly mean of daily high air temperature as the explanatory variable, with the result that 20.5 percent of the variation in the dependent variable was described (Adj. R^2 = .205). The SE for the air temperature-only model was 9.845. Both the constant value and the monthly mean of daily high air temperature variables were significant to a *p*-value of less than .001. The air temperature-only model is shown below:

$$T_{max}^{002} = 67.975 + .310(A_{CF})$$

Equation 23. Equation to relate maximum instantaneous effluent temperature to monthly mean of daily high air temperature at Cleary-Flood Outfall 002.

T_{max}^{002} is maximum instantaneous effluent temperature in °F and A_{CF} is monthly mean of daily high air temperature in °F. The model results indicate that variation in maximum effluent temperature for Cleary-Flood Outfall 002 is dictated far more by air temperature than electricity generation, which may be consistent with the fact that Outfall 002 services a variety of systems including thermal effluent from the boilers of generation Units 8 & 9 as well as other auxiliary systems. It does not serve as an outfall for open-loop, non-contact cooling water. The raw SPSS model output is available as Table A23 in the Appendix.

Water use rate limitations

Two cooling water flow parameters were regulated at Cleary-Flood Outfall 002: monthly average rate of withdrawal (i.e. flow through conduit, rate of water use) and maximum instantaneous flow.

A model to predict the log10-normalized monthly average rate of withdrawal (i.e., flow in conduit) for Cleary-Flood Outfall 002 using log10-normalized net monthly generation for Unit 8 and log10-normalized net monthly generation for Unit 9 as explanatory variables is described with the following equation:

$$\log_{10} q_{avg}^{002} = -1.215 + .071(\log_{10} G_{CF}^{U8}) + .054(\log_{10} G_{CF}^{U9})$$

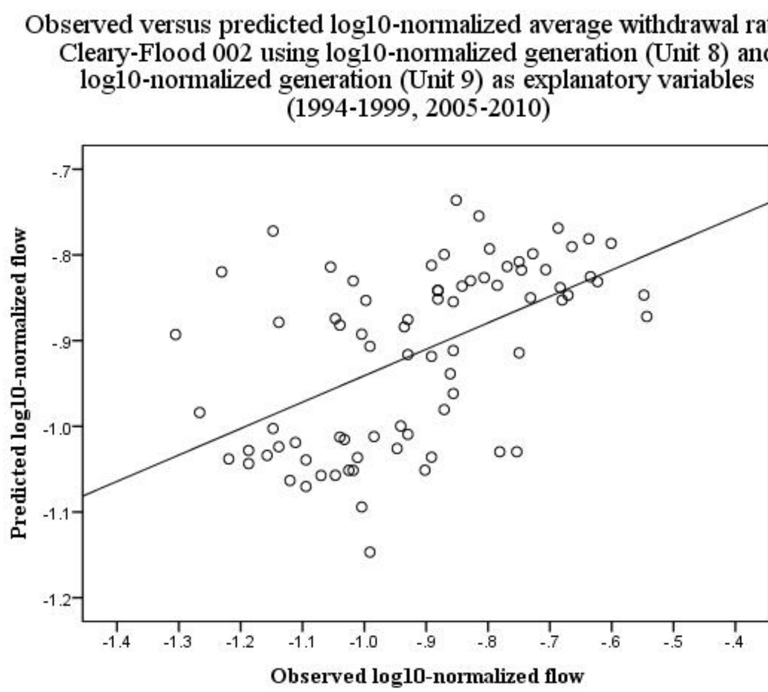
Equation 24. Equation to relate log10-normalized monthly average withdrawal rate to log10-normalized generation in Unit 8 and log10-normalized generation in Unit 9 for Cleary-Flood Outfall 002.

q_{avg}^{002} is monthly average rate of withdrawal in cfs, G_{CF}^{U8} is net monthly generation in Unit 8 (MWh), and G_{CF}^{U9} is net monthly generation in Unit 9 (MWh). The model described 31.3 percent of the variation in the dependent variable (Adj. R^2 = .313) and had an SE of .149. The raw SPSS model output is available as Table A25 in the Appendix.

Table 17. Coefficient summary for model relating log10-normalized average rate of withdrawal to log10-normalized net monthly energy generation in Unit 8 and log10-normalized energy generation in Unit 9 for Cleary-Flood Outfall 002.

	Coeff.	SE	β	t	*p*-value
(Constant)	-1.215	.052		-23.233	< .001
$\log_{10} G_{CF}^{U8}$	.071	.016	.435	4.588	< .001
$\log_{10} G_{CF}^{U9}$	.054	.012	.415	4.375	< .001

Figure 61. Scatter plot of observed log10-normalized monthly average withdrawal rate versus predicted log10-normalized monthly average withdrawal rate for Cleary-Flood Outfall 002, where log10-normalized generation in Unit 8 and log10-normalized generation in Unit 9 are explanatory variables.



A model to predict the log10-normalized monthly maximum instantaneous rate of withdrawal (i.e., flow in conduit) for Cleary-Flood Outfall 002 using monthly mean of daily high air temperature, log10-normalized net monthly generation for Unit 8, and log10-normalized net monthly generation for Unit 9 as explanatory variables is described with the following equation:

$$\log_{10} q_{max}^{002} = -1.238 + .006(A_{CF}) + .052(\log_{10} G_{CF}^{U8}) + .058(\log_{10} G_{CF}^{U9})$$

Equation 25. Equation to relate log10-normalized monthly maximum instantaneous withdrawal rate to monthly mean of daily air temperature, log10-normalized generation in Unit 8, and log10-normalized generation in Unit 9 for Cleary-Flood Outfall 002.

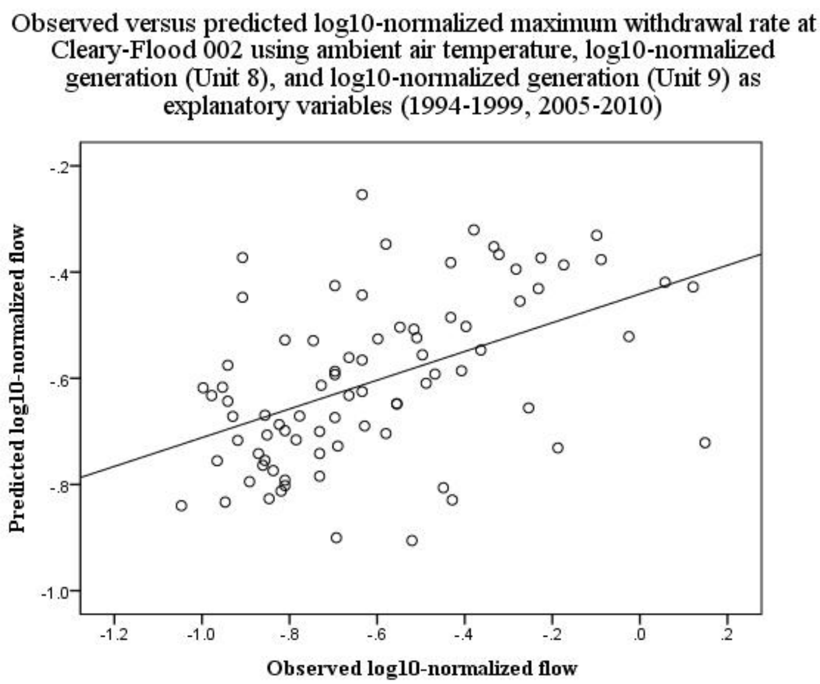
q_{max}^{002} is monthly average rate of withdrawal in cfs, A_{CF} is monthly mean of daily high air temperature in °F, G_{CF}^{U8} is net monthly generation in Unit 8 (MWh), and G_{CF}^{U9} is net monthly generation in Unit 9 (MWh). The model did not improve on the previous, generation-only model, since it described 27.7 percent of the variation in the dependent variable (Adj. R^2 = .277) and had an SE of .240.

Table 18. Coefficient summary for model relating log10-normalized monthly maximum rate of withdrawal to air temperature, log10-normalized energy generation in Unit 8, and log10-normalized energy generation in Unit 9 for Cleary-Flood Outfall 002.

	Coeff.	SE	β	t	*p*-value
(Constant)	-1.238	.114		-10.887	< .001
A_{CF}	.006	.002	.357	3.619	.001
$\log_{10} G_{CF}^{U8}$	.052	.024	.208	2.148	.035
$\log_{10} G_{CF}^{U9}$	.058	.020	.279	2.860	.005

The raw SPSS model output is available as Table A27 in the Appendix.

Figure 62. Scatter plot of observed log10-normalized monthly max withdrawal rate versus predicted log10-normalized monthly max withdrawal rate for Cleary-Flood Outfall 002, where air temperature, log10-normalized generation in Unit 8, and log10-normalized generation in Unit 9 are explanatory variables.



Hindcasting

The cooling water flow rate and effluent temperature models for Cleary-Flood Outfall 002 leave something to be desired in terms of their predictive power—the best model has an adjusted R^2 of only 0.313, and skewness plagued many of the underlying distributions. Due to their meager statistical significance, models describing Outfall 002 were deemed unsuitable for further investigation. It is unfortunate that identifiable patterns did not emerge, since many of Cleary-Floods most blatant violations occurred as a result of the operation of Outfall 002.

Somerset Outfall 007

Temperature limitations

Two temperature parameters were regulated at Somerset Outfall 007: maximum instantaneous discharge temperature and maximum temperature rise between the intake and the outfall (ΔT).

A model to predict the monthly maximum instantaneous effluent temperature at Somerset Outfall 007 using monthly mean of daily high air temperature and total net monthly electricity generation as explanatory variables is described with the following equation:

$$T_{max}^{007} = 26.178 + .830(A_S) + .0001(G_S)$$

Equation 26. Equation to relate maximum instantaneous effluent temperature to monthly mean of daily high air temperature and monthly net electricity generation at Somerset Outfall 007.

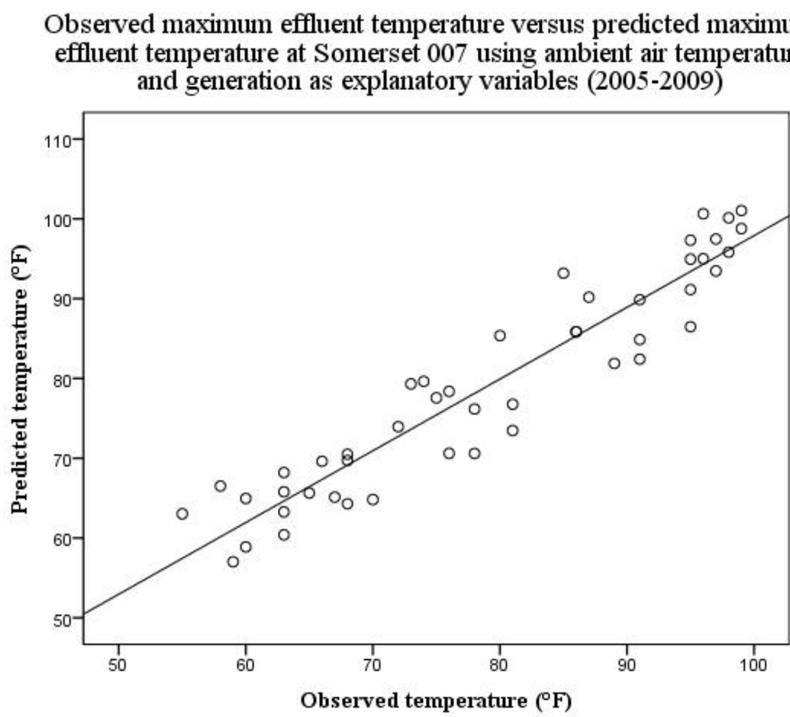
T_{max}^{007} is maximum instantaneous effluent temperature in °F, A_S is monthly mean of daily high air temperature in °F, and G_S is total net monthly electricity generation in MWh. The model described 90.1 percent of the variation in the dependent variable (Adj. R^2 = .901) and had an SE of 4.339.

Table 19. Coefficient summary for model relating maximum instantaneous effluent temperature to monthly mean of daily high air temperature and total net monthly electricity generation at Somerset Outfall 007.

	Coeff.	SE	β	t	*p*-value
(Constant)	26.178	2.874		9.108	< .001
A_S	.830	.041	.945	20.386	< .001
G_S	.0001	.00003	.111	2.392	.021

The raw SPSS model output is available as Table A29 in the Appendix.

Figure 63. Scatter plot of observed max effluent temperature versus predicted max effluent temperature at Somerset Outfall 007, where ambient air temperature and generation are explanatory variables.



A model to predict the monthly maximum instantaneous effluent temperature at Somerset Outfall 007 using monthly mean of daily average streamflow and total net monthly electricity generation as explanatory variables is described with the following equation:

$$T_{max}^{007} = 26.178 + .830(\log_{10} Q_S) + .0001(G_S)$$

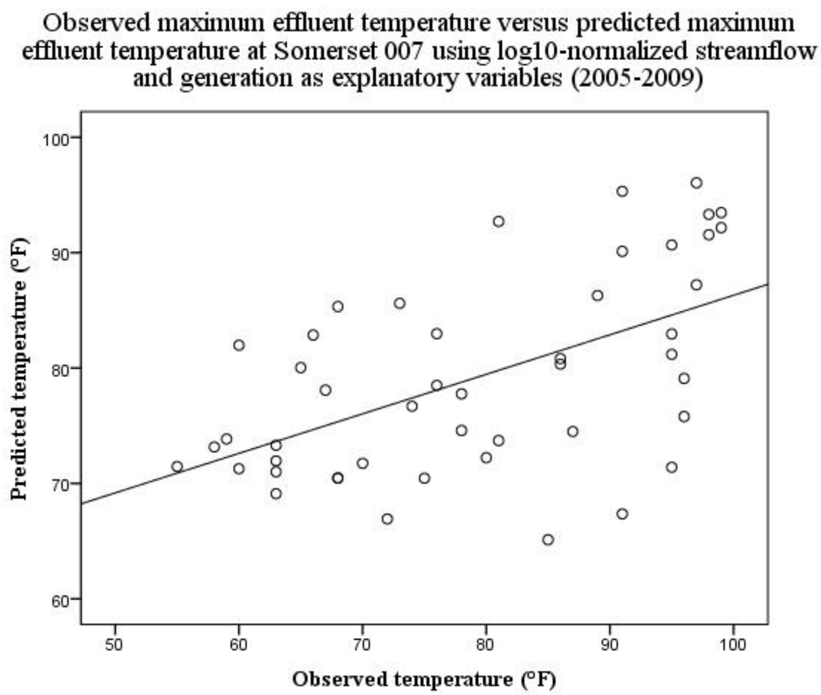
Equation 27. Equation to relate maximum instantaneous effluent temperature to log10-normalized monthly mean of daily average streamflow and monthly net electricity generation at Somerset Outfall 007.

T_{max}^{007} is maximum instantaneous effluent temperature in °F, Q_S is monthly mean of daily average streamflow (cfs), and G_S is total net monthly electricity generation in MWh. The model described only 35.5 percent of the variation in the dependent variable (Adj. R^2 = .355) and had an SE of 11.088. The raw SPSS model output is available as Table A30 in the Appendix.

Table 20. Coefficient summary for model relating maximum instantaneous effluent temperature to log10-normalized monthly mean of daily average streamflow and total net monthly electricity generation at Somerset Outfall 007.

	Coeff.	SE	β	t	*p*-value
(Constant)	150.328	15.027		10.004	< .001
$log_{10}Q_S$	-24.469	4.764	-.613	-5.136	< .001
G_{CF}	.00002	.0001	.034	.288	.775

Figure 64. Scatter plot of observed max effluent temperature versus predicted max effluent temperature at Somerset Outfall 007, where log10-normalized streamflow and generation are explanatory variables.



A model to predict the monthly maximum instantaneous ΔT between the discharge and intake locations for Somerset Outfall 007 using monthly mean of daily high air temperature and total net monthly electricity generation as explanatory variables is described with the following equation:

$$\Delta T_{max}^{007} = 21.903 - .033(A_S) + .00003(G_S)$$

Equation 28. Equation to relate monthly maximum instantaneous ΔT between cooling water intake and discharge points to monthly mean of daily high air temperature and total net monthly electricity generation for Somerset Outfall 007.

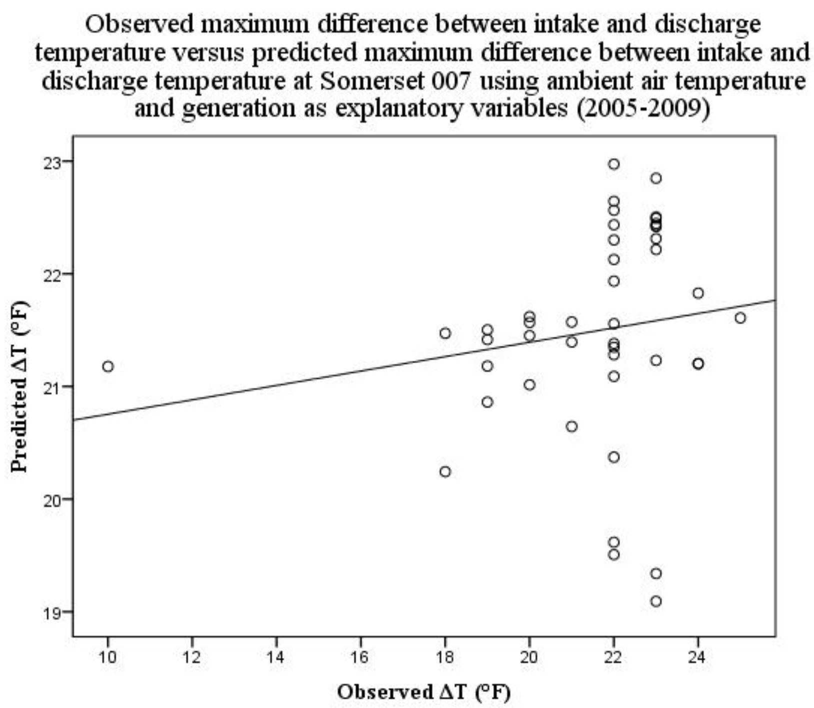
ΔT_{max}^{007} is maximum instantaneous difference in temperature between the intake point and discharge point in F°, A_S is monthly mean of daily high air temperature in °F, and G_S is total net monthly electricity generation in MWh. The model described a mere 9.5 percent of the variation in the dependent variable (Adj. R^2 = .095) and had an SE of 2.299.

Table 21. Coefficient summary for model relating maximum instantaneous ΔT between effluent and intake to monthly mean of daily high air temperature and total net monthly electricity generation at Somerset Outfall 007, including a possible outlier.

	Coeff.	SE	β	t	*p*-value
(Constant)	21.903	1.534		14.279	< .001
A_S	-.033	.022	-.217	-1.494	.143
G_S	.00003	.00002	.307	2.115	.041

The raw SPSS model output is available as Table A32 in the Appendix.

Figure 65. Scatter plot of observed max ΔT versus predicted max ΔT at Somerset Outfall 007, where ambient air temperature and generation are explanatory variables (with a possible outlier).



Another MLR test was performed to test the effects of the outlier, which is visible on the far left in Figure 65, by excluding the outlier. The outlier-free model had an adjusted R^2 value of even less (Adj. R^2 = .070), with an SE of 1.604, indicating that Equation 28 was heavily influenced by the outlier. The larger issue may be the binning that occurs at 22 and 23 °F, visible as columns of open circles in Figure 60. The binning that occurs at whole temperature values is likely an artifact of the preference for reporting whole numbers for temperatures as well as the tendency of the power plant to produce a fairly consistent temperature rise through the condenser.

The temperature rise at Somerset was strictly controlled under a wide range of air temperature and energy generation conditions. The raw SPSS model output for the outlier-free model is available as Table A33 in the Appendix.

Two additional MLR tests were performed using tidal height (i.e., height of mean daily low tide above the MLLW datum). The first MLR test generated a model with a small but slightly better R^2 value than Equation 28 (Adj. R^2 = 0.098) and an SE of 2.295. Excluding the outlier generated a linear model that had an R^2 = .039 with an SE of 1.630. The raw SPSS output for the additional models (not shown) are available as Tables A34 and A35, respectively, in the Appendix.

Water use rate limitations

Two cooling water flow parameters were regulated at Somerset Outfall 007: monthly average rate of withdrawal (i.e. flow through conduit, rate of water use) and maximum instantaneous flow.

A model to predict the monthly average withdrawal rate (i.e., flow in conduit) for Somerset Outfall 007 using monthly mean of daily high air temperature and monthly net electricity generation as explanatory variables is described with the following equation:

$$q_{avg}^{007} = 79.438 + .272(A_S) + .001(G_S)$$

Equation 29. Equation to relate monthly average withdrawal rate to monthly mean of daily high air temperature and total net monthly electricity generation for Somerset Outfall 007.

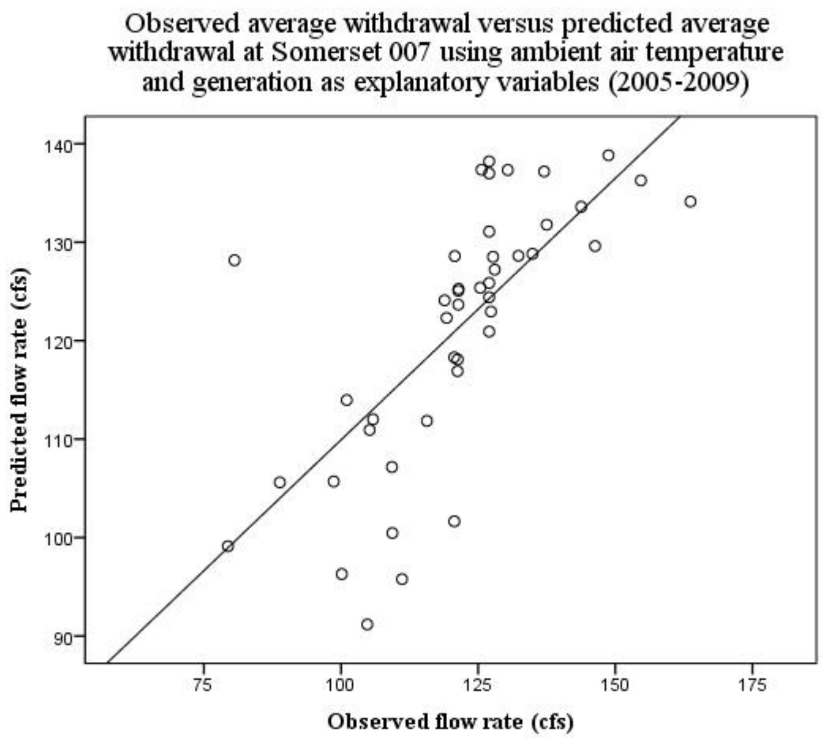
q_{avg}^{007} is monthly average withdrawal rate in cfs, A_S is monthly mean of daily high air temperature in °F, and G_S is monthly net electricity generation in MWh. The model described 54.0 percent of the variation in the dependent variable (Adj. $R^2 = .540$) and had an SE of 11.832.

Table 22. Coefficient summary for model relating monthly average withdrawal rate to monthly mean of daily high air temperature and monthly net electricity generation for Somerset Outfall 007.

	Coeff.	SE	β	t	*p*-value
(Constant)	79.438	7.896		10.060	< .001
A_S	.272	.113	.249	2.407	.021
G_S	.001	.0001	.699	6.752	< .001

The raw SPSS model output is available as Table A37 in the Appendix.

Figure 66. Scatter plot of observed monthly average withdrawal rate versus predicted monthly average withdrawal rate for Somerset Outfall 007, where ambient air temperature and generation are explanatory variables.



A model to predict the monthly average withdrawal rate (i.e., flow in conduit) for Somerset Outfall 007 using log10-normalized monthly average of mean daily streamflow and monthly net electricity generation as explanatory variables is described with the following equation:

$$q_{avg}^{007} = 125.572 - 9.801(\log_{10} Q_S) + .001(G_S)$$

Equation 30. Equation to relate monthly average withdrawal rate to log10-normalized monthly average of daily mean streamflow and total net monthly electricity generation for Somerset Outfall 007.

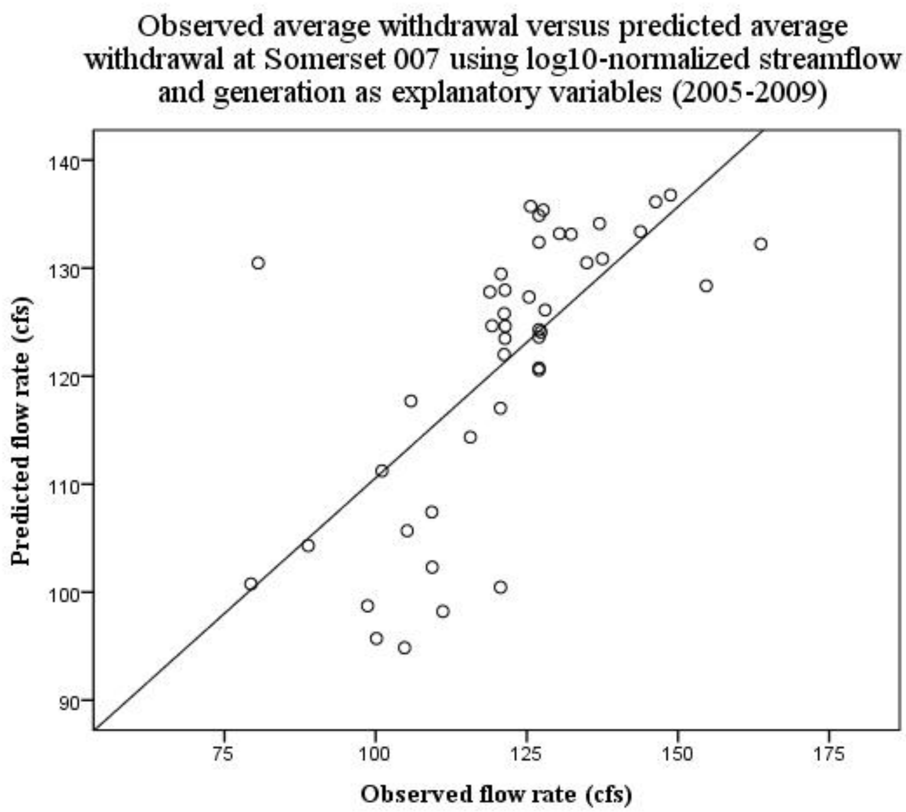
q_{avg}^{007} is monthly average withdrawal rate in cfs, Q_S monthly average of mean daily streamflow of the Taunton River at Somerset, and G_S is monthly net electricity generation in MWh. The model described 51.3 percent of the variation in the dependent variable (Adj. R^2 = .513) and had an SE of 12.182.

The raw SPSS model output is available as Table A38 in the Appendix.

Table 23. Coefficient summary for model relating monthly average withdrawal rate to log10-normalized streamflow and monthly net electricity generation for Somerset Outfall 007.

	Coeff.	SE	β	t	*p*-value
(Constant)	11.667	6.911		1.688	.097
$\log_{10}Q_S$	.689	.050	.869	13.798	< .001
G_S	6.977	.310	.190	3.020	.004

Figure 67. Scatter plot of observed monthly average withdrawal rate versus predicted monthly average withdrawal rate for Somerset Outfall 007, where log10-normalized streamflow and generation are explanatory variables.



A model to predict the monthly maximum instantaneous withdrawal rate (i.e., flow in conduit) for Somerset Outfall 007 using monthly mean of daily high air temperature and monthly net electricity generation as explanatory variables is described with the following equation:

$$q_{max}^{007} = 99.342 + .484(A_S) + .0003(G_S)$$

Equation 31. Equation to relate monthly maximum instantaneous withdrawal rate to monthly mean of daily high air temperature and total net monthly electricity generation for Somerset Outfall 007.

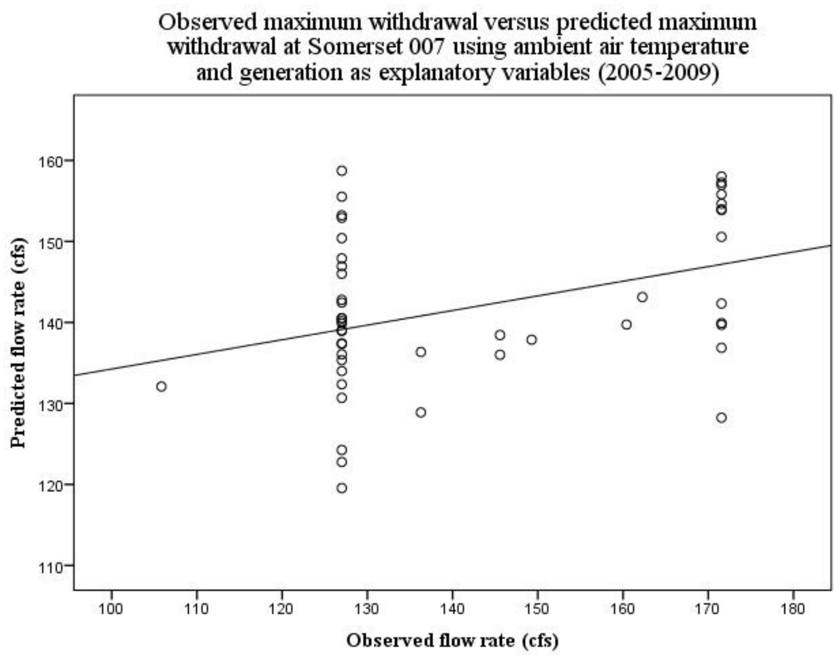
q_{max}^{007} is monthly maximum instantaneous withdrawal rate in cfs, A_S is monthly mean of daily high air temperature in °F, and G_S is monthly net electricity generation in MWh. The model described only 19.6 percent of the variation in the dependent variable (Adj. R^2 = .196) and had an SE of 18.416.

Table 24. Coefficient summary for model relating monthly maximum instantaneous withdrawal rate to monthly mean of daily high air temperature and monthly net electricity generation for Somerset Outfall 007.

	Coeff.	SE	β	t	*p*-value
(Constant)	99.342	12.200		8.143	< .001
A_S	.484	.173	.370	2.800	.008
G_S	.0003	.0001	.305	2.308	.026

The raw SPSS model output is available as Table A40 in the Appendix.

Figure 68. Scatter plot of observed monthly maximum instantaneous withdrawal rate versus predicted monthly maximum instantaneous withdrawal rate for Somerset Outfall 007, where ambient air temperature and generation are explanatory variables.



An additional MLR was performed using log10-normalized monthly average of mean daily streamflow and monthly energy generation as explanatory variables. The resulting model described 22.0 percent of the variation in the dependent variable (Adj. R^2 = 0.220) with an SE of 18.145. The raw SPSS model output is available as Table A41 in the Appendix.

Substantial binning occurred at flow rates of 127 cfs and 172 cfs, indicating operational constraints, which is consistent with several of the conclusions drawn by Dziegielewski and Bik (2006): (1) older plants often stay at full flow even during non-generating standby mode and/or to reduce biofouling, (2) not all cooling water pumps have regulating valves, so that it is necessary to turn individual pumps on or off to regulate flow, (3) at some thermoelectric plants, there is no way to alter the flow without changing the design of system components, and in those situations, no management techniques can be used to alter cooling water flow, and (4) electric load per hour can be regulated simply by adjusting the electromagnetic control on the generator coil, rather than burning more or less fuel, which means that cooling system operation would remain fairly static.

A possible remedy for addressing the largely discrete operation of the cooling system at Somerset would be to use a logistic regression model (i.e., logit model), rather than a continuous linear model. The logit model would allow for binomial regression, where the two possible outcomes—in the face of many different air temperature and electricity generation values—would be a “high” withdrawal rate (e.g.172 cfs) and a “low” rate (e.g. 127 cfs).

Hindcasting

The hindcasting results for Somerset Outfall 007 were similar to those of the other outfalls. Specifically, maximum effluent temperature was the only parameter that appears to have been violated over the 1980-2009 time period. While no temperature violations appear to be on record, the high number of model-predicted violations, combined with the high explanatory power of the associated model (Adj. $R^2 = 0.901$), virtually guarantees that Somerset has violated its permit limitations in the past, or that it has been forced to dial back its generation on many occasions in the past. Neither the EIA power generation database nor the monthly discharge monitoring reports can demonstrate whether or not this was the case, so non-statistical verification (e.g. direct communication with the Somerset power plant managers) would strengthen the findings.

The models for maximum ΔT, maximum instantaneous flow rate, and average flow rate generated no alleged violations. The highest ΔT value generated was 22.8 F°, and its limitation was 25 F°. Both cooling water flow parameters appear to have always been far below the limitations set forth by the permit. The highest instantaneous flow rate generated was 175 cfs, and its limitation was 579 cfs. The highest average flow rate generated was 221 cfs, and its limitation was 427 cfs. All three peak values are estimated to have occurred in July 1984.

Table 25. Hindcasting results for Somerset Outfall 007 showing observed and predicted values (1980-2009).

Year	Month	Max Temp, Predicted (°F)	Max Temp, Observed (°F)	Permit Limit (°F)
1980	7	103.7	NR	100
1980	8	103.1	NR	100
1981	7	103.1	NR	100
1983	6	103.2	NR	100
1983	7	108.8	NR	100
1983	8	106.0	NR	100
1983	9	102.2	NR	100
1984	7	105.2	NR	100
1984	8	106.0	NR	100
1985	7	106.5	NR	100
1985	8	103.2	NR	100
1987	7	103.6	NR	100
1987	8	102.9	NR	100
1988	7	103.6	NR	100
1988	8	105.7	NR	100
1989	7	104.5	NR	100
1989	8	102.8	NR	100
1990	8	103.6	NR	100
1991	7	102.7	NR	100
1991	8	105.0	NR	100
1992	7	100.4	NR	100
1994	7	103.4	NR	100
1995	7	102.0	NR	100
1995	8	100.2	NR	100
1996	8	100.7	NR	100
1997	7	102.7	NR	100
1998	7	102.6	NR	100
1998	8	101.8	NR	100
2001	8	102.5	NR	100
2002	7	104.4	NR	100
2002	8	103.0	NR	100
2003	8	102.7	NR	100
2004	7	101.2	NR	100
2005	7	102.8	NR	100
2005	8	104.8	NR	100
2006	7	102.4	96	100
2007	7	102.2	98	100
2007	8	100.6	99	100
2008	7	103.0	99	100

Estimated number of violations over 1980-2009 time period = 39.
Number of violations on record = 0.
NR means not recorded at the MassDEP SERO or in the ECHO database.

CHAPTER 5

METHODOLOGY: PART II

Forecasting demonstration introduction

The results of the multiple regression analyses and hindcasting study indicate that the most appropriate and trustworthy models to use for predicting the frequency of potential dial-back and/or NPDES permit violations are for maximum discharge temperature, T_{max}. Specifically, the two models most suited for forecasting were for (i) maximum discharge temperature at Cleary-Flood Outfall 001 (T_{max}^{001}), using air temperature and log10-transformed net electricity generation as explanatory variables (Equation 14) and for (ii) maximum discharge temperature at Somerset Outfall 007 (T_{max}^{007}), using air temperature and net electricity generation as explanatory variables (Equation 26). In addition to having high and statistically significant R^2 values, the hindcasting reveals the high likelihood that each of the two power plants has been in violation of their permit for maximum discharge temperature in the past as a result of contemporaneously high air temperatures and electricity generation values.

Other models were excluded due to their failure to generate sufficiently high R^2 values and small *p*-values during the statistical analysis. None of the water withdrawal models for each power plant showed a high enough correlation between environmental and operational variables (e.g. streamflow, air temperature, net electricity generation) and cooling water flow rates to be of predictive value. Furthermore, neither power plant has ever reported maximum and average water withdrawal values that even approached their permitted limits. In other words, rates of water withdrawal were not a major concern for these specific plants. The models for maximum temperature rise through the condenser (i.e., ΔT_{max}), where measured, were similarly disappointing, showing only very low correlations between monthly energy generation and environmental variables. While maximum ΔT has been an issue for Cleary-Flood Outfall 001—two violations are on record for this parameter—the quality of the corresponding models was too poor to be useful in forecasting.

Finally, Cleary-Flood Outfall 002 is excluded from the forecasting section of this research. None of the models sufficiently demonstrated a consistent relationship between the explanatory variables and the dependent variables investigated. This is unfortunate because of the high frequency of water withdrawal violations occurring for Cleary-Flood Outfall 002 in the past. The inadequacy of multiple linear regression modeling to capture the core operational aspects of Outfall 002 is not surprising, however, given the multiple uses of the conduit. Unlike Cleary-Flood Outfall 001, which primarily serves the once-through cooling system, flow through Outfall 002 originates from no fewer than seven separate and erratically contributory sources: boiler blowdown, boiler blowdown “quench” water, auxiliary equipment cooling water, carbon filter back wash, neutralized demineralizer regeneration wastes, floor drain water, and storm water.

Revisiting the maximum discharge models for Cleary-Flood Outfall 001 and Somerset Outfall 007, Equation 14 and Equation 26, respectively, shows that a credible forecast has three requirements:

1. A reasonable power plant life span (60-70 years)
2. High resolution air temperature predictions
3. Reasonable energy generation predictions for each facility

As thermoelectric facilities go, Cleary-Flood and Somerset are quite old. Whether each plant is actually operating in one or two decades depends on the economic health of the managing entities, the political climate in Massachusetts, and near-term technological innovations. For instance, Somerset is currently closed as a consequence of its failure to comply with air emission restrictions, and it is unclear whether NRG Energy will make the substantial financial investment required to bring it into compliance and reopen it. Cleary-Flood, meanwhile, may increasingly rely upon its closed-loop cooled natural gas turbine systems, which have not been modeled here.

For the purposes of demonstrating the utility and deployability of the model, it is assumed that both power plants will be operational until 2030. While the two power plants are old, they are not anachronistic within the larger context of electricity producers in the U.S. and worldwide. Electricity consumers will continue to rely upon both new *and* old sources of power, and while these facilities may have permanently shuttered their doors within 20 years, many will not have.

Temperature predictions

In an attempt to accurately synthesize current global AOGCMs and to bring their conclusions to bear, the United Nations convened the Intergovernmental Panel on Climate Change (IPCC), which was made up of over 500 lead authors and 2,000 reviewing scientists (Betts, 2011). The IPCC documented their findings in the Fourth Assessment Report released in 2007 (Pachauri & Reisinger (Eds.), 2007). Two major conclusions of the report are that the rise of Earth's average temperature since 1950 is due largely to anthropogenic greenhouse gas emissions (Kirshen et al., 2008), and that such emissions ensure a steady rise of global average temperatures over the next few decades.

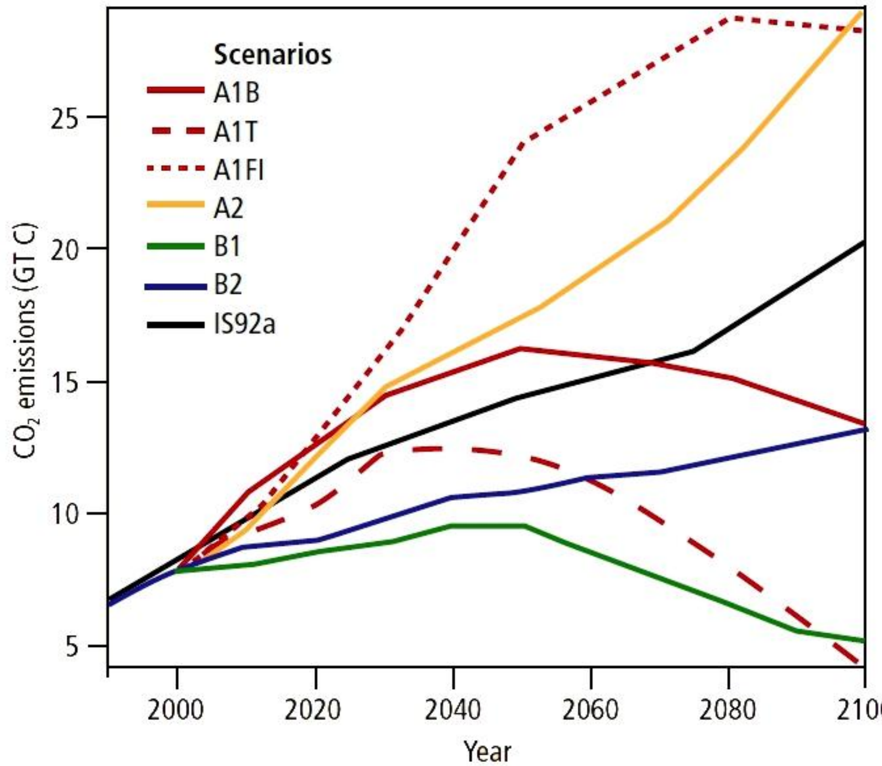
Heat-trapping gases can remain in the atmosphere for hundreds of years after being released. Meanwhile, the ocean takes time to respond to such atmospheric changes. The result of these two factors is that there is a generational lag time between when greenhouse gases are released and when the effects (e.g. air temperature increases, increased hydrological volatility) are perceived (Frumhoff et al., 2007).

In fact, average annual temperatures in the Northern Hemisphere have increased roughly 1.3 °F in the last 100 years, due largely to atmospheric concentrations of carbon dioxide gas (CO_2). Atmospheric CO_2 levels are higher now than they have been in over half a million years. The ever-increasing CO_2 levels are due primarily to the burning of fossil fuels for transportation and electrical energy. The heat effects of the rising greenhouse gas levels are exacerbated by the increase in atmospheric water vapor and the loss of ice cover in high latitudes—both of which are caused by air and water temperature increases. Water vapor is another greenhouse gas, while sea-ice acts to reflect incoming solar energy back out to space (Betts, 2011).

In 2006, a research group called the Northeast Climate Impacts Assessment (NECIA) successfully downscaled three of the major AOGCMs (i.e. PCM, CM2.1, and HadCM3), and documented their findings in a report titled *Climate Change in the U.S. Northeast* (Frumhoff et al., 2007). The intent of the project was to generate high resolution (i.e., one-eighth degree, daily) projections of air temperature and precipitation patterns in the Northeast for a time horizon extending to 2100, and under high (A1fi) and low (B1) greenhouse gas emissions scenarios (Hayhoe et al., 2007). A range of possible emissions scenarios have been developed by the IPCC (Figure 69).

The NECIA climate scientists attempted to capture the full range of climate variation due to human causes by selecting the high and low emissions scenarios. The lower-emissions scenario (B1, shown as the solid green line) projects total atmospheric CO_2 concentrations to reach 550 ppm by the end of the century, compared to 380 ppm today. The higher-emissions scenario (A1fi, shown as the

Figure 69. CO2 emission scenarios published by the IPCC, showing gigatons of carbon (GT C) released by humans from 2000-2100 (Frumhoff et al., 2007, p. 4).



dotted red line) projects atmospheric CO_2 concentrations to be closer to 940 ppm by the end of the century.

The granularity of preexisting models served to limit their ability to recreate observed climate phenomena at a scale relevant to regional planners. Historically, water management in the U.S. has been based on historical precipitation statistics, but the assumption that future precipitation patterns will be predictably consistent with past conditions is no longer valid (Betts, 2011). Still, historical environmental conditions are useful for calibrating a dynamic representation of the environment. As Betts (2011) notes, society "uses two complementary frameworks when planning for the future: 1) Regional projections from climate models [and] 2) Climate trends…[from] recent decades" (Betts, 2011, p. 1).

After Wood et al. (2002), the NECIA researchers applied statistical bias removal and downscaling methods to coarse-scale AOGCMs to improve the accuracy and relevance of the models' ability to simulate the natural variability in air temperature and precipitation patterns in the Northeast (Hayhoe et al., 2007). Based on the principle that historical environmental observations can be misleading, but are scientifically valuable, the NECIA researchers selected a subset of U.S. Historical Climatology Network (USHCN) data stations across the Northeast based on record length and quality, covering the years 1961-1990 (Hayhoe et al. 2007). Probability density functions (PDF) of precipitation and air temperature were generated for each of the locations based on the available AOGCMs for the same set of years. In the most basic terms, the mean and variability of each PDF was adjusted to match the observed data.

Overall, the researchers were satisfied with the downscaling approach to adjust for the biases and improve the spatial resolution of the three AOGCMs investigated. The adapted simulations generated values for the Northeast that were "relatively close to observed climatology for the 1990s" (Hayhoe et al., 2007, p. 11). For temperature, the statistical approach diverged only slightly from the PCM-driven dynamic regional model when simulating the future. The researchers were similarly satisfied with the precipitation values. For both temperature and precipitation, the majority of statistical downscaling-generated values were within 5% of those generated by the dynamic PCM (Hayhoe et al., 2007).

The authors highlight three major qualifications when presenting their methods and conclusions. First, daily temperature and precipitation values were statistically derived from the global models' monthly means, so they may not reflect atmospheric circulation as expressed in each dynamic model at daily or weekly timescales. Second, the statistical downscaling method performed poorly with precipitation anomalies, and did not align well with the dynamic model predictions in such cases. The temperature predictions were free of such caveats (Hayhoe et al., 2007). Lastly, the authors warn that the reported parameters are not meant to "predict" the weather, but can only offer a guide to the probability of long term climate change at various time scales (Hayhoe et al., 2008).

The researchers have documented the results of their analysis as a permanent hyperlink available for anyone to use (Hayhoe et al., 2008). They conclude that average summer air temperatures in the Northeast can be expected to rise between 1.5-3.5 F° and average winter air temperatures to rise between 2.5-4.0 F° over the next 30-40 years. The near term increases are expected to occur irrespective of the fossil fuel combustion choices made today, because sufficient levels of greenhouse gases already exist in the atmosphere for temperature forcing to occur (Frumhoff et al., 2007). The frequency of extreme air temperature and precipitation events is also expected to increase in many areas of the region.

Air temperature data

Ultimately, the air temperature figures provided by the NECIA researchers can be considered the best available predictions for the study area. In some ways, the predictions are fairly conservative, because no daily or monthly temperature extremes appear in the model. The timing of such extremes are incredibly difficult to predict, and may be impossible to predict as weather events. Therefore, model-generated future dial-back and/or violation values, discussed in Chapter 6, should be considered conservative estimates about the possibility of such events occurring. It is entirely likely that more will occur, but unlikely that fewer will occur.

Figure 70 shows observed interpolated monthly mean of daily high air temperature for each of the two study sites (1970-2010), as well as the NECIA model-generated monthly high air temperature predictions for Massachusetts for the A1Fi and B1 emissions scenarios (2011-2030). There is only slight variation between the two study sites, with observed air temperatures at Somerset being slightly more extreme on a handful of occasions. The periodicity and range appear very similar between the observed and predicted values. The busyness of Figure 70 is reduced by creating a 12-month moving average of air temperatures, as shown in Figure 71. With a 12-month moving average, the value of each month is shown as an average of the previous 12 months, serving to smooth the graph. The complete listing of the NECIA predicted air temperatures under the A1fi and B1 emissions scenarios for the period (2011-2030) is available in Table A42 in the Appendix (Hayhoe et al., 2008).

Figure 71. Observed monthly mean of daily high air temperatures (1970-2010) and predicted monthly maximum air temperature (2011-2030).

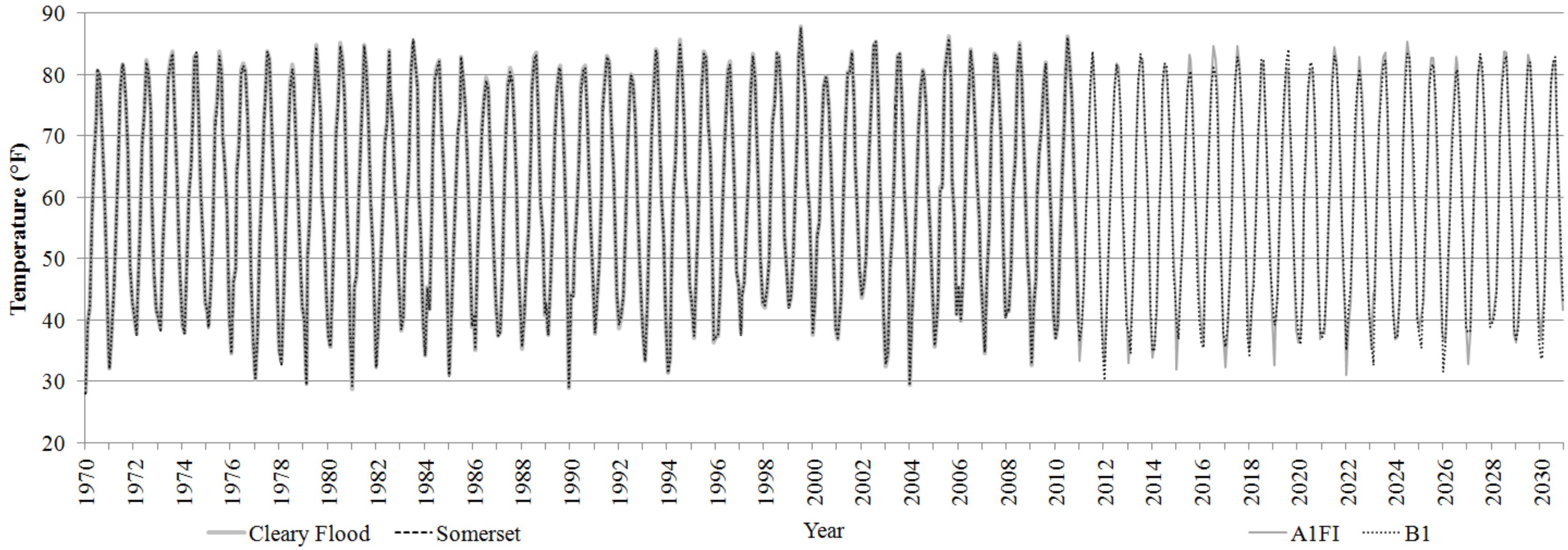
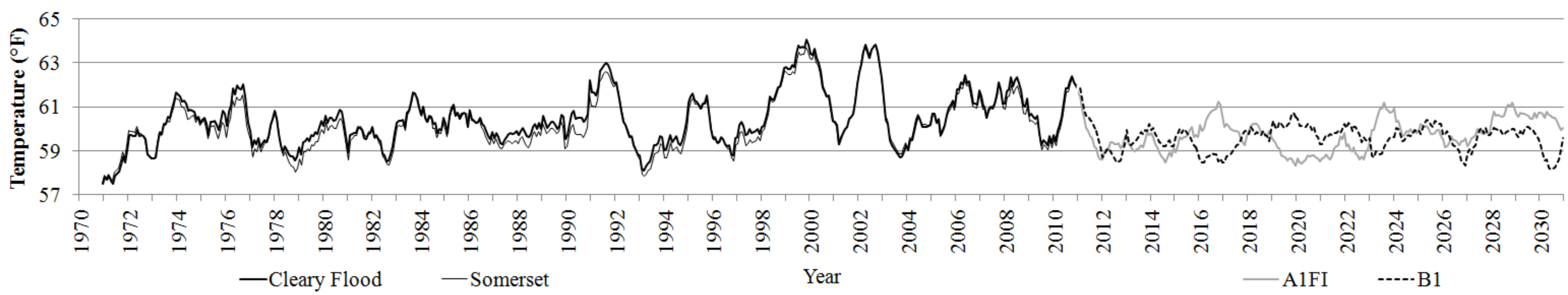


Figure 70. 12 month moving average of observed monthly mean of daily high air temperatures (1970-2010) and predicted monthly maximum air temperatures (2011-2030)



Variability between the air temperatures at the two study sites becomes easier to see with the 12 month moving average, as does the variability under the A1fi and B1 emissions scenarios. The major differences between the observed data and the predicted data are apparent, but not alarming. First, the range of values under either the A1fi or the B1 emissions scenarios is smaller than the range of observed values. The predicted values fall within a fairly narrow range, and do not show the occasional high temperatures that have been observed at the two study sites. On a few occasions, the predicted 12-month average temperatures under each emissions scenario are roughly equal in magnitude, but opposite in sign from their average (i.e., the average of A1fi and B1 temperature predictions). Again, this indicates that predicted discharge temperatures at each site—and the associated frequency of dial-back or violation events—will serve as a conservative lower-limit to the true values. Only a very slight average air temperature rise is evident over the 20 year period from 2011-2030, but the growth is far smaller than the interannual variation.

Electricity generation predictions

Each year has offered a new set of electricity demand challenges for power plant operators at Cleary-Flood and Somerset. Some years were unusually warm, causing managers to adjust their output in response to ISO requests. Some years found the power plants doing maintenance that caused certain generating units to be completely offline. Power plant retrofits and new regulations also lead to variability in each power plant's electricity generation. In some cases, additional units were installed, and the load was taken off of some units and put onto others. Populations have changed and residential and commercial energy efficiency measures have been put into place. Such variation makes predicting monthly electricity generation values for individual power plants notoriously difficult. One way that power plant operators cope with this uncertainty is by keeping adequate supplies of their fuel source accessible. Federal and state energy agencies reduce the volatility by aggregating values across thousands of power plants, offering averages and growth values that are generally meaningful only at the "50,000 foot" planning level.

The standard for predictions about future energy consumption and electricity demand growth in the U.S. is the Annual Energy Outlook (AEO), which is published by the EIA (EIA, 2011d). The AEO offers a comprehensive review of energy trends over the past year, and incorporates energy supply data, economic data, population growth data, and a suite of other variables to give predictions about energy supplies and demands for many sectors over the coming decades. As we have seen, national trends are not always indicative of regional trends, and are even less likely to offer meaningful insight into the yearly operation of an individual power plant. A simple repetition of past average electricity generation at each power plant is also unlikely to offer the degree of accuracy that a power plant manager or NPDES permit reviewer might desire. Therefore, several steps were followed in order to arrive at two possible electricity generation scenarios. First, baseline monthly energy generation values were selected. These values represent the monthly mean generation at each plant from the most recent period in the past when no major variation in electricity generation appears to have occurred. In Scenario 1, the “no growth” scenario, monthly electricity generation values are repeated through time, so that electricity generation in 2030 for each of the units is precisely the same as it was over the preceding period of low variability.

A scatter plot of monthly electricity generation of Cleary-Flood Unit 8 shows no obvious trends in output through time. During a multi-month period occurring between 2002-2004, the unit was non-operational, and no electricity was generated by it on various other occasions. There is a possible downward trend in output through time, but probably not enough to dismiss the possibility of continued average operation or even growth.

The generation for Somerset Units 5 and 6 shows a somewhat different story. It is generally far less variable than that of the Cleary-Flood unit, which is not surprising, since Somerset is a base load facility, rather than peaking plant. As Figure 73 shows, generation through Units 5 & 6 has been decreasing in steps through time. The most recent step appears between 1995-2007, with the only significant multi-month interruption occurring around the year 2000. From 2008 to the present, electricity generation fell off at Somerset, as the managing company litigated with public agencies over its emissions compliance. Nevertheless, the stable period between 1995-2007 was selected as a reasonable candidate for inserting mean monthly electricity generation into the model.

The next step was to select a suitable growth factor for use in the model in order to create Scenario 2. Over the period of 1980-2005, the average annual increase in electricity consumption in the U.S. was 2.2 percent. The rate in Massachusetts was only slightly less at 2.1 percent per year (EERE, 2008). In this case, the Commonwealth appears to be in line with the national trend. The similarity between Massachusetts' electricity consumption growth rate and U.S. is fortuitous, because it makes the national predictions more useful at the scale of relevance to the model. Table 26 shows the expected annual electricity growth from 2009-2035 for three major sectors in the U.S. (EIA, 2011d). It also shows a breakdown of total electricity consumption in Massachusetts by major sector (EERE, 2008).

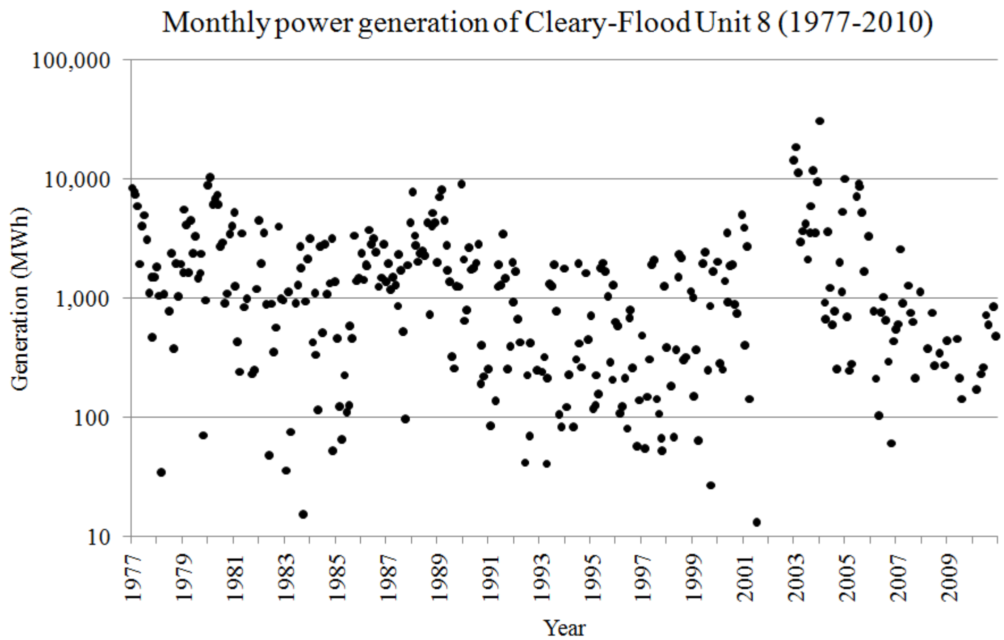
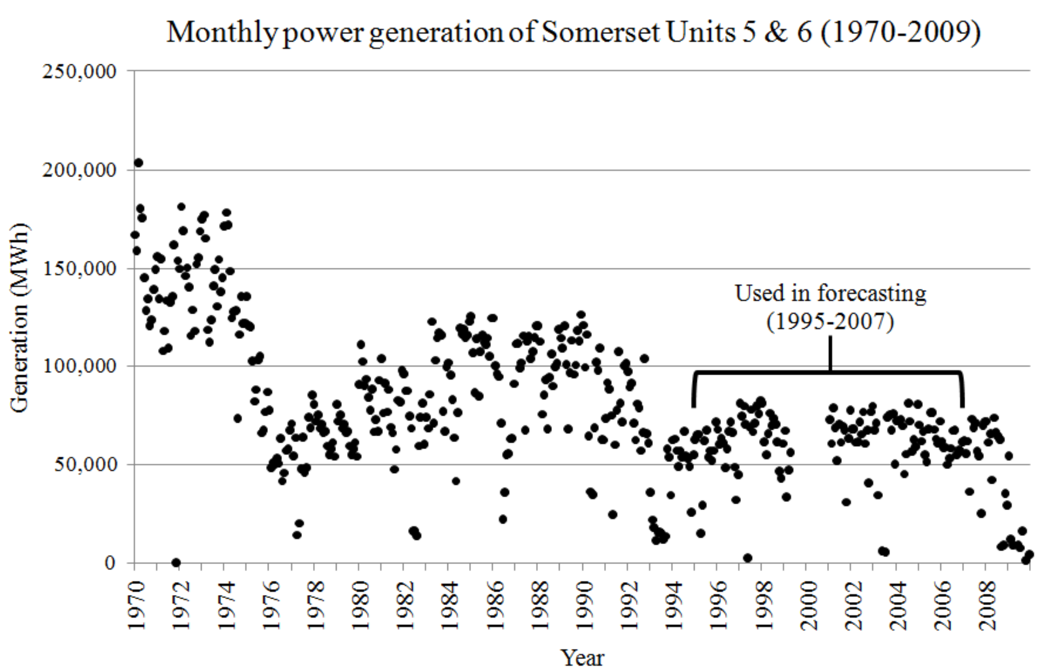


Figure 72. Scatter plot of monthly power generation of Cleary-Flood Unit 8 (1997-2010).

Figure 73. Scatter plot of monthly power generation of Somerset Units 5 & 6 (1970-2009), showing the subset of data selected for forecasting.



Expected growth rates for the three major sectors (i.e., Commercial, Industrial, and Residential) are multiplied by the percentage of Massachusetts' total electricity consumption that each sector is responsible for in order to provide an overall growth estimate. Note that in the EIA AEO data, electricity related losses—which can be substantial—are not included in the calculus and whisker plots) illustrate the median, upper and lower quartiles, and any outliers. Another marker shows where expected monthly electricity generation would be by 2030 with 0.95 percent annual growth, and a representation of the range of values used in the forecasting model.

Figure 74 bears a striking resemblance to Figure 29. In fact, they are nearly identical, with the exception of the addition of the median growth values. The maximum effluent temperature discharge model for Cleary-Flood Outfall 001 (Equation 14) is based on the log10-normalized energy generation, so the effect of the 0.95 percent annual growth is actually quite small—signified by the small rise visible between the black median bars and the white median bars.

Table 26. An approximation of expected annual electricity consumption growth in Massachusetts for the period 2009-2035 (adapted from EIA 2011 data).

Sector	U.S. - projected electricity annual growth rate (%)	MA - percent of total electricity consumption (%)	Percent-weighted projected annual growth rate for Massachusetts (%)
Residential	0.7	36	0.252
Commercial	1.4	46	0.644
Industrial	0.3	17	0.051
		TOTAL	0.95

The corresponding figure for Somerset (Figure 75) shows a greater apparent change between the no growth and growth scenarios. The change is a consequence of the choice of scale for the y-axis. Unlike the Cleary-Flood box-plots, it is not log10-normalized. The maximum discharge temperature model for Somerset Outfall 007 is based on straight generation values (Equation 26), rather than normalized values, which means that there is a greater difference between the expected impacts of the two electricity consumption growth scenarios on Somerset than on Cleary-Flood. As one might expect, the upper, lower, and median values of Figure 75 are lower than those shown in an earlier graphic of Somerset Unit 5 & 6 generation by month (Figure 39). This is a consequence of the selection of only a subset of the 40 years worth of generation data for Units 5 & 6.

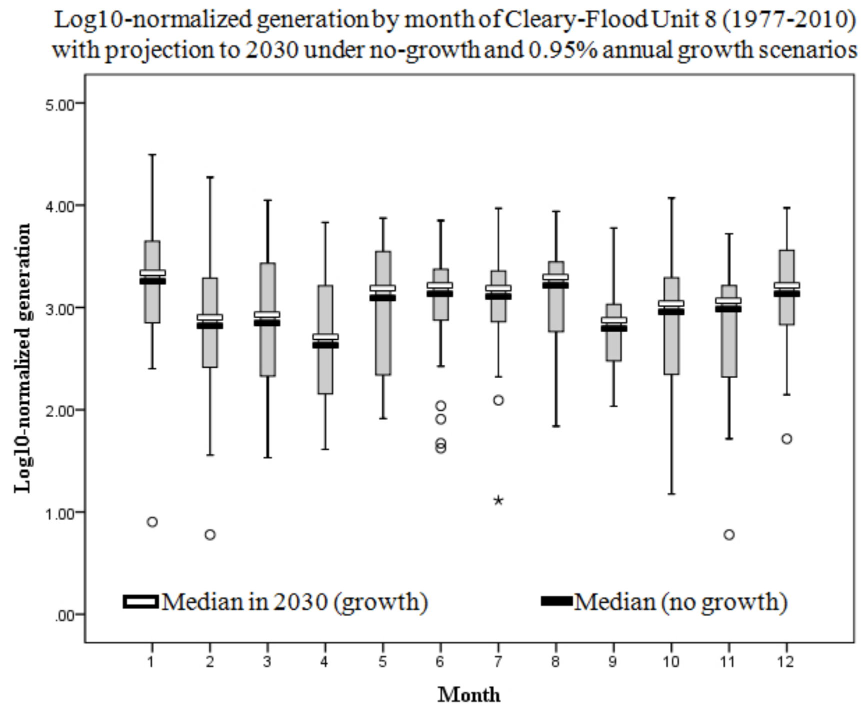
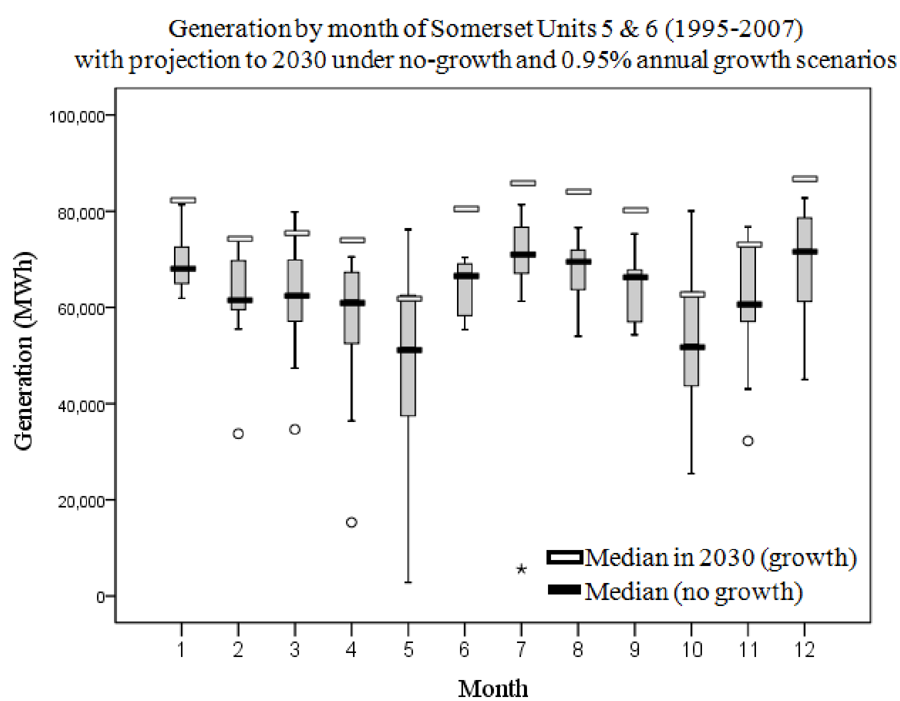


Figure 74. Box-plots of electricity generation by month of Cleary-Flood Unit 8 under electricity consumption growth and no growth scenarios to 2030 (1997-2010).

Figure 75. Box-plots of electricity generation by month of Somerset Units 5 & 6 under electricity consumption growth and no growth scenarios to 2030 (1997-2010).



Ultimately, there is not a one-to-one relationship between population increases and energy consumption. Over the last few decades, population in Massachusetts has increased, but the economy has seen a shift from heavy manufacturing to service industry jobs. Nor is there a direct relationship between residential electricity consumption growth rates and the amount of nameplate capacity necessary to meet that demand. Electricity generation losses may be minimized with advanced grid technology and the replacement of older power plants with new ones. New laws, efficiency mandates, and a revised clean energy standard (CES) may have the effect of decreasing the burden on Massachusetts' existing energy generation infrastructure in favor of electricity from outside of the state or country (Vandana Rao, MassEEA, 16 August 2011). Whether Somerset and Cleary-Flood can be expected to generate electricity at favorable rates for the utilities and surrounding consumers remains to be seen. The maximum effluent discharge model is only relevant for months when the power plants—and specifically the individual generators and outfalls being regulated—are in operation.

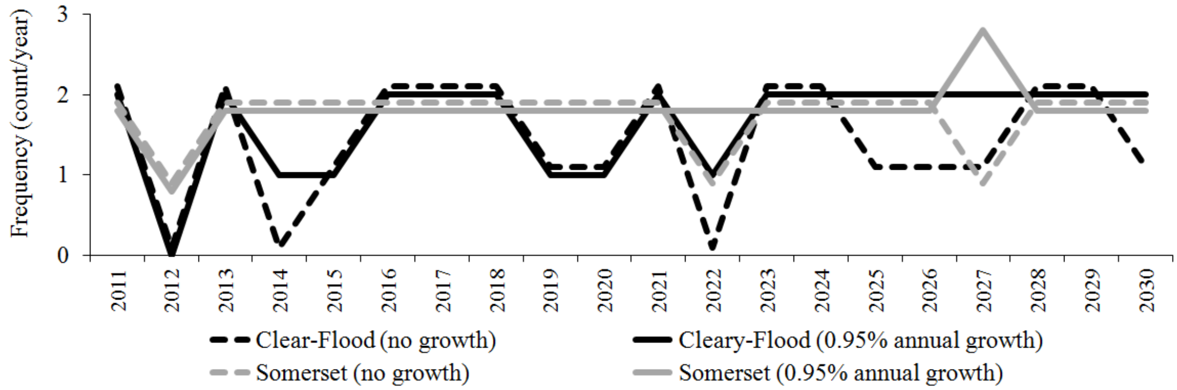
CHAPTER 6

RESULTS AND DISCUSSION: PART II

A basic question of this analysis is whether Somerset and Cleary-Flood can be expected to face NPDES permit compliance challenges in the future. The simple answer is that, under strict permit reporting and enforcement, they *can* expect to face such challenges. Historically, the power plants have been cited for withdrawal rate violations and temperature rise violations, but never maximum effluent temperatures violations. If history is a guide, they can expect to face the same challenges they have always faced, with the possible addition of maximum effluent temperature violations. One metric of concern for environmental regulators may be the number of expected violations per year for each of the two outfalls (i.e., Outfall 001, Outfall 007).

The previous graphic (Figure 76) shows two possible compliance futures for Cleary-Flood Outfall 001 and Somerset Outfall 002. With only a few exceptions, and regardless of whether electricity generation grows for each generator, maximum effluent temperature standards will present a challenge for each of the plants. If plant managers decide to provide electricity to meet demand at all times, they will violate their permits at least as often as the frequencies shown. What is more likely, however, is that power plant managers will choose permit compliance over full electricity

Figure 76. Predicted frequency of NPDES permit-related operational challenges for Cleary-Flood and Somerset under electricity demand growth and no growth scenarios, projected to 2030.



supply, introducing unforeseen chokepoints into the electricity supply structure in which the region finds itself.

Another point of concern is the timing of such operational and compliance challenges. At what time of the year are they most likely to occur? Table 27 shows that violations or dial-back can be expected during the hottest parts of the year, which is consistent with the conclusions of previous studies (Elcock et al., 2010; Miller et al., 1992; Yang and Dziegielewski, 2007). More precisely, most of the environmental choke points are expected to occur in July and August of future years.

From 1991, there is a marginal increase in the number of potential dial-back/violation events occurring per year for each decade (Table 28). During the 1990's and within the limitations of this model, Cleary-Flood could have been expected to deal with maximum effluent temperature-related constraints on its operation at least 1.2times per year, compared with 1.4 times per year by the 2020's under static energy demand

Table 27. Forecasting results for maximum effluent temperature at Cleary-Flood Outfall 001 and Somerset Outfall 007 under static versus growing electricity consumption.

Year	Month	Cleary-Flood Outfall 001 Max. effluent T (°F)		Somerset Outfall 007 Max. effluent T (°F)	
		No growth	0.95% annual	*No growth*	0.95% annual
2011	7	90.9	90.9	102.6	102.6
2011	8	-	90.1	100.4	100.5
2012	7	-	-	101.2	101.3
2013	7	90.6	90.6	102.2	102.4
2013	8	90.7	90.8	101.2	101.4
2014	7	-	-	101.2	101.5
2014	8	-	-	100.3	100.5
2015	7	-	-	101.1	101.4
2015	8	90.4	90.5	100.8	101.2
2016	7	90.5	90.7	102.1	102.5
2016	8	90.2	90.3	100.6	101.0
2017	7	91.1	91.3	102.9	103.4
2017	8	-	90.2	100.4	100.9
2018	7	90.1	90.3	101.6	102.1
2018	8	90.7	91.0	101.3	101.8
2019	7	-	-	101.1	101.7
2019	8	90.8	91.1	101.4	102.0
2020	7	-	-	100.8	101.5
2020	8	90.2	90.4	100.6	101.3
2021	7	91.1	91.4	102.8	103.6
2021	8	90.7	91.0	101.2	102.0
2022	7	-	90.1	101.2	102.0
2022	8	-	-	-	100.4
2023	7	-	90.4	101.5	102.5
2023	8	91.4	91.8	102.1	103.0
2024	7	91.6	92.0	103.4	104.4
2024	8	91.3	91.7	101.9	102.9
2025	7	-	90.3	101.3	102.4
2025	8	90.8	91.2	101.4	102.4
2026	7	-	90.2	101.2	102.4
2026	8	90.1	90.5	100.5	101.6
2027	6	-	-	-	100.4
2027	7	90.6	91.1	102.3	103.5
2027	8	-	90.2	-	101.2
2028	7	90.4	90.9	102.0	103.3
2028	8	91.6	92.1	102.3	103.6
2029	7	90.2	90.8	101.8	103.2
2029	8	90.7	91.2	101.2	102.5
2030	7	-	90.5	101.4	102.8
2030	8	91.0	91.6	101.6	103.0

A dash (-) indicates that the maximum effluent temperature limitation was not exceeded. Cleary-Flood's limitation is 90°F. Somerset's limitation is 100°F.

conditions and at least 1.8 times per year for the same decade under the 0.95 percent annual electricity consumption growth scenario. Similarly, in the 1990's, Somerset would have expected to choose between dialing back its electricity generation for Units 5 & 6 or violating its permit roughly once per year, compared with 1.8 times per year in the 2020's under a no growth scenario, and 2.1 times per year under the electricity consumption growth scenario.

Table 28. Average number of model-generated dial-back/violation events per year by decade for Cleary-Flood Outfall 001 and Somerset Outfall 007.

Decade	Cleary-Flood Dial-back/violation events per year		Somerset Dial-back/violation events per year	
	No Growth	*Growth*	*No Growth*	*Growth*
1991-2000	1.2	-	1.0	-
2001-2010	0.9	-	1.1	-
2011-2020	1.3	1.3	1.9	1.9
2021-2030	1.4	1.8	1.8	2.1

Limitation thresholds

Another potentially useful set of figures are the relevant thresholds (e.g. air temperature, electricity generation). Based on Equation 14 and Equation 26, and based on the percentiles for monthly mean of daily high air temperature and monthly net electricity generation, it is possible to show the point at which permit limitations will be reached under high, median, and low air temperatures or electricity generation conditions.

Table 29 shows air temperature and electricity generation values for three percentiles—Low (5th percentile), Median (50th percentile), and High (95th percentile), where only 5 percent of the values fall below the given air temperature or generation value for Low, half fall below for Median, and 95 percent fall below for High.

For each of the percentile values, there is a corresponding air temperature or electricity generation value that reveals the point at which the maximum effluent limitation for the given outfall will be reached, in accordance with the model (Table 30). For instance, in a month of typical electrical generation for Cleary-Flood (i.e., 50th percentile, 1,481 MWh), the monthly mean of daily high air temperatures only needs to reach 81.6 °F for a violation or dial-back situation to be likely. For Somerset, the relevant air temperature value for Somerset under 50th percentile electricity generation is 80.3 °F. Meanwhile, under High air temperature conditions (i.e., based on historical data, not on climate change predictions), Cleary-Flood must only generate approximately 980 MWh for a violation or dial-back event to be likely, whereas Somerset would have to generate 50,245 MWh for an event to be likely. Table 30 also reveals some limitations of the model. For example, under Low and Median air temperatures, Cleary-Flood Unit 8 would have to generate values that are well outside of its possible range of operation (e.g. greater than 174,541 MWh). Likewise, it would be extremely unlikely, if not impossible, for Somerset Unit 5 & 6 to generate the number of megawatt·hours necessary to reach a violation level under Low and Median air temperature conditions. The model is obviously driven primarily by air temperature values, which has implications that will be discussed in Chapters 7, 8, and 9.

More revealing are the monthly mean of daily high air temperatures necessary under Low, Median, and High electricity generation conditions for operational challenges to be likely. For instance, under High generation conditions for Cleary-Flood and Somerset, daily air temperature for a given month must only reach about 72°F on average for violation/dial-back events to occur.

Table 29. Air temperature and electricity generation for Somerset and Cleary-Flood at various percentiles over the period of record for each.

Parameter	Cleary-Flood			Somerset		
	Low (5%)	*Median* (50%)	*High* (95%)	*Low* (5%)	*Median* (50%)	*High* (95%)
Air Temp. (°F)	35.3	60.6	83.4	36.0	60.2	82.9
Generation (MWh)	124	1,481	13,617	16,469	71,672	149,227

Table 30. Violation or dial-back thresholds for High, Median, and Low monthly air temperature and electricity generation values for Cleary-Flood Outfall 001 and Somerset Outfall 007.

Thresholds	Cleary-Flood	Somerset
Low Air Temp. (5th percentile)	55,551,197 MWh	439,345 MWh
Median Air Temp. (50th percentile)	174,541 MWh	238,270 MWh
High Air Temp. (95th percentile)	980 MWh	50,245 MWh
Low Generation (5th percentile)	92.5 °F	87.0 °F
Median Generation (50th percentile)	81.6 °F	80.3 °F
High Generation (95th percentile)	71.8 °F	71.0 °F

Forecasting error

There are many sources of error that propagate through to the final model. Air temperature values have been estimated through time by many different thermometers and reported by many different offices. Energy generation values were measured and reported directly by power plant operators in some cases, and statistically extrapolated by Energy Information Administration data analysts in other cases. Furthermore, there is error introduced into the model because of the fact that only a sample of the full population of effluent temperature values was available. While the known and unknown sources of error cannot be eliminated from the model, the conservative approach taken may mitigate the problems of uncertainty.

Revisiting Equation 14 and Equation 26, it becomes clear that the hindcasted and forecasted maximum effluent temperature values may be larger or smaller than those reported here. Confidence intervals are an important way of showing where the true mean of a population is likely to lie. For instance, according to Equation 14, at a 95 percent confidence level, any one of Cleary-Flood's estimated maximum effluent discharge temperatures may be 12.9 F° higher *or lower* than what the model provides. The reason for this is that the Standard Error (SE) for the estimate is 6.604, and a confidence interval at the 95th percentile level may be calculated for the estimate by multiplying the SE by 1.96 (a rule of statistics for normally distributed populations).

Similarly for Somerset, according to Equation 26, at a 95 percent confidence level, any one of Somerset's estimated maximum effluent discharge temperatures may be

8.5 F° higher or lower than what the model reports. While it would be tempting to conclude that all of the hindcasted and forecasted values reported here may fall *below* the two permit limits (e.g. 90°F and 100°F) and hence, *no violations or dial-back events have occurred or are likely to occur*, it is important to recognize that it is just as likely that *more* violations and dial-back events have occurred and will occur if the true values are many Fahrenheit degrees higher than those the model reports. Much of this uncertainty could be remedied by better data collection and reporting, but for the moment, and given the disparate data sources used and initial heterogeneity of data quality across the different databases, it is probably worth taking the maximum predicted effluent temperatures at face value.

There is a substantial opportunity to improve the forecasting component of this methodology. For instance, daily measurements would add relevance to the model for power plant operators and would increase the utility of precise, but otherwise inadequate monthly averages. The study may be more useful in capturing the two peaks of electricity demand that occur by season (i.e., summer and winter), with the possibility that statistical uncertainty surrounding electricity generation values could be reduced. Regression equations may be developed that relate Massachusetts average expected monthly high temperatures to the monthly mean of daily high temperatures observed at each site, so that the temperatures used in forecasting better reflect those that are likely at each site.

While forecasting at the monthly scale and within the context of permitting may not hold a great deal of interest for power plant operators—who work at the scale of the day, hour, or minute—it may hold a great deal of potential for systems level and long term analyses that seek to understand permit-related operational bottlenecks for the benefit of human health and the environment.

CHAPTER 7

METHODOLOGY, RESULTS, AND DISCUSSION: PART III

Introduction

In the future, Cleary-Flood and Somerset power plants are highly likely to either violate their thermal discharge permits, dial back their power generation unexpectedly, or both. The following section provides a framework for using the model to reduce the likelihood of those undesirable outcomes. There are many potential solutions to the problems inadvertently created by the NPDES permitting process. In this chapter, the model is used to test a few of them.

The newness of explicit study of the Energy-Water Nexus and the dearth of relevant literature made a review of existing methodologies insufficient to address the central challenge of this research. In fact, there are no studies that view power plants as a population of acting agents whose behavior is partially a consequence of the rules by which they must exist (i.e., physical, regulatory). Most of the literature that addresses the relationship between environmental and thermoelectric systems is found in engineering journals, manuals, and textbooks. There, the relationship is generally treated unidirectionally. Specifically, environmental conditions change and so must operational conditions at the facility. For instance, a guide to power plants might tell you which pumps to buy and when to turn them on or off. It might also explain the thermophysical relationship between the heat input, flow, and temperature change in the cooling water. Environmental science literature also treats the relationship as unidirectional, but typically only considers the impacts of the power plant, rather than viewing the facility and its natural setting as systems which influence one another. A reader of these texts finds information on the physiological impacts of thermal loading on aquatic biota, the gruesome details of impingement and entrainment of fish, physical habitat damage, and so forth. Peer-reviewed literature describing the regulatory mechanisms in place that are meant to limit the risks to power plants posed by unforeseen environmental extremes (e.g. air and stream temperature variation, reduced water availability) is sparse.

Meanwhile, official federal guidance on how to create a quality water use permit for a large thermoelectric facility is inconsistent. Many permits today are written based on the best professional judgment (BPJ) of the writers and reviewers and only focus on best available technologies for the avoidance of harm to ecosystems. They were written to minimize harmful discharges, not for the purposes of ensuring that the power plant can generate power during all times of societal need and within normal environmental variation. And even when permits are expertly crafted and vigorously enforced, much of the U.S. electrical capacity relies on aging cooling systems that predate the Clean Water Act, and which have been grandfathered into compliance under §316(a) variances.

In reality, a power plant and its host environment are part of one system which has inadequately understood energy and water dynamics. Government regulators, industry scientists, and academics are increasingly recognizing the importance of this interplay. Some are experts whose research fits poorly within the boundaries of the traditional fields of engineering, economics, biology, and environmental science. Energy-water nexus studies have begun to bridge some of these traditional knowledge gaps.

Conversations

In order to craft reasonable responses to the problems that older, moderately-sized thermoelectric facilities face in a warming climate, I supplemented the literature review with expert testimony. The unusualness of the topic and model necessitated this strategy. The purpose was to get a broader view of the options available and to investigate those which were most promising.

Over the course of several months, I was fortunate enough to attend two major conferences that focused on the water demands and impacts of energy production. The first, hosted by the Groundwater Protection Council, was attended by a number of government scientists, industry representatives, and independent consultants who deal with water and energy problems on a day-to-day basis, and who are on the leading edge of many national energy-related water issues.

The second conference, hosted by the American Society of Mechanical Engineers (ASME), focused on the connection between our water and energy systems. Many of the attendees were mechanical and civil engineers by training, representing private industry, various universities, and government. The diversity of technical and professional backgrounds represented at the ASME conference was exemplified by one panel session in particular. It included two national lab scientists, a representative from a power plant component manufacturer, a power plant manager, and a scientist from a leading non-profit energy firm (from Sandia National Lab, NREL, ALSTOM, Southern Company, and the Electric Power Research Institute, respectively). Fueling the discussion were academics from various universities.

During a series of one-on-one conversations, discussion groups, presentation, and panels, I collected specific recommendations for reducing power plant dial-back and thermal effluent violations. Those potential solutions are outlined in the following paragraphs. In speaking with environmental engineers, regional planners, civil engineers, environmental regulators, state and federal scientists, geologists, hydrologists, mechanical engineers, and physical chemists, among others, I gained a deeper understanding of the Energy-Water Nexus as a whole, including insight into which research needs may be the most urgent. Table A43 in the Appendix gives a listing of the individuals whose testimony was used to guide the process of crafting solutions.

Potential solutions

Possible responses to the conflict between providing electrical power and protecting the environment fall into four general categories: *permit compliance modification*; *physical changes to the generating unit and its cooling system*; *additions to the plant that are external to the generating unit*; and *activity modification*.

Permit compliance modification includes any solution that requires a change to each power plant's NPDES permit and/or changes to the consequences of non-compliance. Physical modifications include any additions or changes to the generating unit and/or its cooling system. External modifications include the other physical changes that could be made to the plant which do not require modification of the generating system and its cooling system. Activity modifications require a change in behavior on the part of the power plant operator and/or the electricity consumers, but not physical changes to the plant.

Within the following discussion of each potential solution is an assessment of each solution's viability as a practical solution based primarily on its ability to prevent environmental harm where compliance with its existing permit is used as a proxy. Secondarily, each solution was judge based on its ability to meet consumers' electricity demands. If dial-back had to occur, incremental changes to the output were preferred to sudden changes in order to minimize the likelihood of sudden brownouts.

One solution to the unintended consequences of each plant's NPDES permit is to simply change the temperature threshold to which each power plant is held. For example, Cleary-Flood has a limitation of 90°F, so raising the threshold to 95°F would automatically allow the power plant to avoid dial-back and avoid permit violations, *ipso facto*. Consumer electricity demands would also be met. The obvious problem with this response is that the environment would suffer harm. The limit for Cleary-Flood was set at 90°F—just as the limit for Somerset was set at 100°F—in order to protect aquatic biota.

The purpose of the permit is to prevent environmental harm, so the permit would become valueless.

MassDEP or the US EPA might consider increasing the fines associated with non-compliance as well as the frequency of inspections—essentially toughening enforcement. Such a method would certainly help protect the environment, but it may increase the frequency of rapid dial-back events as the power plant attempts to avoid heftier fines. The power plant operator would be in an even more difficult situation. Consumer demand for electricity would be even harder to meet. And, in the absence of frequent and rigorous facility inspections by federal and state officials or automated reporting, under-reporting of violations may become even more common.

Adding pumping capacity would require a capital investment on the part of the power plant, but assuming its "flow in conduit" limits are sufficiently high, the pumping capacity would allow the plant to maintain its level of power output while also abiding by its thermal effluent limit. To the extent that the power plant was not violating its permit, environmental protection would be achieved. Rapid dial-back would be delayed as the power plant took full advantage of its withdrawal limitations, but it would not be prevented. Consumer demand would be met for a longer period than if withdrawal rates were kept constant. The concept of trading cooling water temperature increases (ΔT) with higher flow (q) has merit and is explored in greater detail in the Solutions section.

Adding auxiliary, "emergency" cooling towers to run during the hottest months would ensure that there were fewer high-flow thermal discharges to the downstream environment. The overall environmental benefit may be outweighed by additional environmental costs, such as habitat destruction during construction and within the cooling towers' footprint, as well as discharges of cooling system blowdown that often contains high total dissolved solids and high salinity. If those impacts are negligible though, an environmental benefit would be achieved. Financially, the systems and retrofit required could be very expensive, although they are likely to be small compared to a scenario where the facility does nothing and is consistently penalized. Similarly, social backlash to constructing additional cooling equipment can make such projects impractical, but may also be outweighed by the public's priority for a more reliable electricity supply and fewer sudden deratings.

Installation of air cooling systems would have a substantial environmental benefit at the site of the plant (e.g. no high volume, high temperature effluent). The power plant would no longer need a permit specific to 316(a) and 316(b) provisions of the Clean Water Act for its cooling water effluent, but it would be harder to guarantee a steady supply of electricity to consumers. Dial-back during hot weather would occur due to significant hardware and safety constraints associated with air-cooled systems. The switch to air-cooled systems may positively or negatively impact the ability of the power plant to provide electricity to meet consumer demand depending on the temperatures at which the constraints become significant.

External modifications might include installation of a reservoir or cooling pond; use of nearby groundwater during extremely hot days or days where streamflow is very low; an addition of a refugium for impacted fish species; or an addition of an ice production and storage facility.

Cooling ponds and cooling canals are variations of the same idea. They would have the effect of providing an additional buffer between the power plant and its environment. For a hybrid system, water would be withdrawn from the river, used within the power plant to generate electricity, and then discharged into a cooling pond. A cooling pond acts like a natural draft tower, allowing much of the heat to escape to the atmosphere as water vapor. In a truly hybrid system, some of the water from the cooling pond would be pumped back into the plant, thereby reducing the amount of water required from the river. With a cooling canal, the water would travel some distance along a manmade conduit to cool before returning to the river.

Whether use of either of these options would be better or worse for the environment and power plant depends largely on the way that it is built. Such systems would certainly reduce the temperature of the discharge before returning to the designated confluence with the river, but can also consume much greater quantities of water than once-through systems. In some cases, the cooling ponds are indistinguishable from natural lakes and can play host to the water fowl or other aquatic organisms. The impact of the cooling water on animals would depend on the quality of the effluent water. Overall, the additional buffer would help the power plant to avoid rapid, permit limitation-related dial-back, and would make it easier for the power plant to meet consumer demands in the face of strictly enforced permit limitations.

Another method of insulating the power plant from the natural environment and vice versa is by using groundwater resources during extreme hot weather or low streamflow events. At least one such example is a thermoelectric facility in Washington

County, Georgia, which has been successfully using a confined Cretaceous aquifer to supplement its cooling needs during low flow events (Kresic et al., 2011). There are some logistical issues involved with switching from surface water sources to groundwater sources (e.g. treatment), but they are minimal. In the area of that power plant, there are substantial fresh groundwater resources. The facility also makes use of a 1,250 acre-foot storage tank on site, adding an additional stopgap for when they must switch to the groundwater cooling system.

The major environmental shortcomings would be the impacts of the construction necessary to put it into place, and the possibility of high temperature discharges downstream of the facility during low flow events when the river is less able to dissipate heat. It has at least two practical shortcomings. The first is the fact that both Cleary-Flood and Somerset are coastal facilities. The aquifer below each of the facilities is likely to be a low-yielding, bedrock type aquifer and unsuitable for high withdrawals (E. Douglas, personal communication, February 13, 2012). The fact that the Cretaceous aquifer is confined brings up another issue, too: it is relatively disconnected from the river in the area of the facility, so draw-down of the aquifer in that area of Georgia has very little effect on the flow of the stream. That may not be the case at all at Cleary-Flood and Somerset. While intriguing, too many uncertainties surround the environmental soundness and practical viability of such a project for it to be considered here.

Many of the other external modifications suffer from similar uncertainties. Refugia for negatively impacted fish species have been used at power plants in New Mexico near the Rio Grande River to replace many of the larvae that are lost to impingement and entrainment at once-through facilities there (M. Hightower, personal communication, October 6, 2011). It is difficult to quantify the total negative impacts that high temperature, high volume effluents have on their downstream environments at Cleary-Flood and Somerset. It is also unclear whether the genetic diversity of the replaced fish species would be great enough to account for total losses in the downstream habitat. Biodiversity is essential to ensuring species survival in the presence of disease, and so genetically similar organisms are more likely to be wiped out entirely during an epidemic. In any event, refugia would do nothing to help each of the power plants abide by its existing permit, avoid raid dial-back, or meet consumer demand during hot weather events.

Still other options include installation of a combined heat and power (CHP) system and ice storage. CHP is a system in which hot water generated at the power plant is pumped to a nearby building for space heating. CHP is most useful during the winter time when space heating is needed most, and not during the summer time, when the power plants are suffering heat excesses. Installation of a CHP system may ease heat load under conditions of normal air temperature, but may do nothing to avoid sudden dial-back when the additional heat rejection through the building is too small.

Cool thermal energy storage (TES) would allow each facility to bank its energy generation as ice during a period of low stream temperatures and lower electricity prices (e.g. night time) and then use it when air and stream temperatures are higher by reintroducing the ice into the water before intake (Nguyen, 2011). Electricity production occurring at night would go to the production of ice, and the ice would be stored in a nearby facility until it was needed during the day time. Since facilities need a large ΔT to produce electricity, they would be able to reduce the intake water temperatures, even when the ambient air temperatures are increasing. This type of system has promise and, theoretically, it may reduce the risk of sudden dial-back and help each facility meet electricity demand, but significant uncertainty remains, because the technology is not yet mature.

The final category of response is based only on changes to activity using the existing infrastructure. It is the category for which the MLR models for Cleary-Flood and Somerset are most useful. Demand side management (DSM) is where government, industry, or both promote certain types of behavior to encourage consumers to become more energy efficient. Examples include tax credits for the installation of low-wattage devices and installation of energy efficient windows, or education about low-energy cooling methods. DSM-driven energy efficiency is generally regarded as “low-hanging fruit” within the field of energy sustainability and urban planning. A successful DSM campaign would have environmental benefits because power generation would be reduced. The power plant would be less likely to risk permit violation in the face of lower demands. Consumers’ electricity needs would be lower, but fulfilled. Use of DSM is especially attractive to the power plants when their revenue is decoupled from total electricity consumption by consumers, or when the rate structure is designed in such a way that the price per kilowatt or kilowatt·hour increases as the total demand increases.

Many utilities have the option of buying electricity from different power plants in order to continue providing power to their customers. When a power plant’s usual customers begin purchasing their electricity from other areas, environmental harm is reduced in the location of the power plant, but potentially shifted to another area. From the perspective of the consumer, the energy supply remains uninterrupted, but only if other power plants are not suffering from the similar heat stresses. Somerset, for example, is currently closed because of its inability to meet minimum emissions requirements. In this case, the environment at the site is well served, but customers may only have found the shut-down acceptable because they had the option of consuming electricity from other power plants. Strictly speaking, the generating unit at Somerset no longer supplies electricity to meet customer demand. The overall benefits of this strategy are unclear, because environmental harm and the risk of air temperature-induced dial-back may simply have been shifted to another location.

The last activity modification is related to an earlier point: adding pump capacity. If the power plant operators can increase the flow through their plant, it is possible to maintain output while abiding by their temperature limitations. Indeed, this is often exactly what happens. In this scenario, electricity demand growth is followed by additional fuel combustion, which is followed by the production of additional waste heat. This is followed by a rise in effluent temperatures until plant operators are compelled to increase flow, according to the relationship previously shown in Chapter 2. While it cannot continue indefinitely, it is a vital tool used by power plant operators to supply electricity while fulfilling the requirements of their NPDES permit. Environmentally, the solution is sound to the extent that the permit is being followed. Sudden dial-back is further avoided as the facility takes full advantage of its withdrawal allowances. Once both the temperature and withdrawal limitations were reached, sudden-dial back would still occur. Consumer demands are fully met for a longer period of time.

The following graphic summarizes the results of the previous discussion. A plus sign (+) indicates a positive impact (i.e., good for the environment, meets consumer demand, or avoids rapid dial-back); a minus sign (-) indicates a negative result; a plus sign and a minus sign (+/-) indicates the results could be positive, negative, or would have an uncertain result.

Table 31. Summary of potential responses to thermal effluent permit violations and dial-back associated with avoiding such violations.

Category	Response	Description	Environmental Health	Consumer needs	Gradual dial-back
Permit compliance	*Change temperature threshold*	Raise the limitation of the threshold; for instance, from 90° F to 95° F	-	+	+
	Change fines for non-compliance	Increase the fines associated with non-compliance; increase the frequency and intensity of inspections	+	-	-
Unit and cooling system	*Change pumping capacity*	Add pumping capacity to the cooling system by installing additional pumps	+/-	-	+
	Add auxiliary cooling towers	Install emergency cooling towers (recirculating) for hottest months	+	-	+
	Convert to air cooling	Replace the existing once-through system with an air cooled system	+	-	-
External modification	*Convert to a hybrid system, or reservoir*	Install a body of water to use as a heat buffer between outfall and river	+/-	-	+
	Use groundwater	Draw from groundwater resources	+/-	+/-	+/-
	Add a refugium	Install a fish hatchery at the power plant to replace lost fish	+/-	+/-	+/-
	Add an ice production facility	Produce electricity during low ambient temperatures; store excess energy as ice	+	+	+
	Combined heat and power	Send hot water to a neighboring building for space heating	+	+/-	+/-
Activity	*Demand side management*	Decrease demands on the power plant by promoting energy conservation by end users	+	+	+
	Buy electricity from elsewhere	Replace lost electricity with electricity from elsewhere	+/-	+	+
	Shut down operating unit	Dial back generation until it reaches zero, remains off	+	-	+/-
	Change flow through conduit	Increase the cooling water flow through plant using existing pumps	+	+/-	-

Benefits of avoiding harm

Each of the proposed solutions is worthy of its own detailed econometric analyses, which I do not attempt here. The benefits of avoiding harm to the environment are many. This section offers a description of the financial benefits of avoiding harm, especially from the perspective of the power plant managers. For instance, what are the penalties and compliance costs that each power plant must pay when it is issued an official citation? Are those costs typical? How do those costs compare to what each plant might expect to earn in a month during the hottest part of the year (e.g. July, August)?

The first question is the easiest to answer. Cleary-Flood was issued a formal citation in 2006 for a host of violations, including "fail[ure] to comply with oil & grease monitoring provisions, fail[ure] to maintain adequate laboratory practices,…fail[ure] to maintain pH within acceptable limits," among others (EPA, 2008). It was allowed to pay a reduced penalty of $15,000 to the federal government in exchange for funding a $50,000 supplemental environmental project (SEP) carried out by the University of Massachusetts Dartmouth. Its compliance action cost (CAP), which included all of the expenditures needed to come back into compliance, was $110,900. The total amount paid by the City of Taunton to bring their facility back into compliance was $175,900.

According to one EPA report from 1990, the average penalty paid by facilities for NPDES permit violations in 1989 was $31,552 (EPA, 1990b), or $57,929 in 2012 dollars (BLS, 2012), so the total penalty and SEP cost of $65,000 does not appear to be anomalous. No other formal citations are on record for either Cleary-Flood or Somerset, although a few informal citations (i.e., alleged violations and warnings) have occurred. The implication is that either the plants avoid violating their permits by derating their facilities during very hot conditions or violations were missed due to the limited resources available to the MassDEP and the EPA for NPDES compliance enforcement—or both.

However, if one compares the penalty to lost earnings that occur at when the Cleary-Flood generating unit is offline, it is high. Table 32 provides the calculation steps necessary to estimate those profits. It shows values for both Cleary-Flood and Somerset, including average monthly energy output for the two hottest months of the year, retail price of electricity, and earnings of each power plant as a percentage of revenue, and total profits for one day, one week, and one month, respectively. Table 32 also shows that the one-time penalty of $65,000 would have been comparatively small for Somerset.

The monthly output value was calculated by taking the average generation of each for July and August, covering the same time period used in the forecasting section under the No Growth generation scenario. The retail electricity prices were reported by the EIA for 2010 for the City of Taunton, but not Somerset (EIA, 2011e). For the latter, an average of retail prices was calculated using the retail prices reported for five other investor-owned power plants in Massachusetts[1] and weighted by the amount that they generated. Profit as a percentage of total revenue was calculated using an annual report

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[1] Massachusetts Electric Co., NSTAR Electric Company, Nantucket Electric Co., Fitchburg Gas and Electric Company, and Western Massachusetts Electric Co.

provided online by Cleary-Flood for 2008 (TMLP, 2008).[2] Profit as a percentage of total revenue was estimated for Somerset by selecting the "Utilities: Gas and Electric" category as a proxy from a report released by Fortune Magazine in 2008 (Fortune, 2008). Actual earnings could be much higher or much lower for Somerset. At the very least, though, the provided figures offer a worthwhile placeholder for more accurate numbers.

Table 32. Estimate of earnings for Cleary-Flood Unit 8 and Somerset Unit 6 over different time periods.

Plant	Monthly output (kWh)	Price of electricity ($/kWh)	Profit as percent of revenue (%)	Time period	Earnings ($)
Cleary-Flood	1,470,000	0.1432	3.325	Day	233
				Week	1,628
				Month	7,080
Somerset	70,372,000	0.1424	7.9	Day	26,007
				Week	181,990
				Month	791,657

Ultimately, there is a very strong incentive for power plant managers to provide electricity to consumers, right up to the point of violation. Indeed, in many cases, facilities are required *by law* to provide a certain amount of electricity to the public, because they are regulated monopolies (W. Skaff, personal communication, September 26, 2011). But the final guiding principle is whether or not the power plant can continue to operate at a profit.

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[2] The average of profit as a percentage of revenue for Cleary-Flood was 2.53% in 2007 and 4.12% in 2008. An average of those was taken to arrive at 3.325%. By law, profits at Cleary-Flood cannot yield more than 8% annually.

For any given year, the installation of a new system to control for pollution or to prevent habitat destruction is counted as a cost, but it must also be weighed against the cost of inaction, especially if more intensive monitoring by state and federal environmental officials occurs. If violations were rigorously enforced, and assuming the average cost of their violations is equal to the $57,929 mentioned earlier, Cleary-Flood would face a total cost of over $1.39 million dollars for the 24 violations that the model predicts will occur over the 2011-2030 time period (Table 27). Likewise, Somerset would face a total cost of $2.14 million dollars over the same time period for its 37 model-predicted violations (Table 27)

If the capital costs of installing new technology to mitigate thermal impacts and secure the electricity supply are too high, each plant might consider retiring its once-through cooled units outright in order to avoid future penalties for environmental harm.

The following section explores three of the proposed solutions in greater detail. The assumes that withdrawal rates are fairly fixed and requires the power plant to gradual dial-back its generation while increasing fees in abnormally hot months. By employing a pricing scheme in which prices rise in tandem with air temperature, some degree of DSM occurs while power plants recoup revenue losses associated with their NPDES compliance. The second relies on each power plant's ability to control flow. The final potential response takes elements of both of the preceding solutions to generate a more desirable outcome. It is then modified to reflect the economic effects.

Solution 1 Introduction

The first potential solution relies on the relationship between energy generation, ambient air temperature, and effluent temperature, established by Equation 14 for Cleary-Flood and Equation 26 for Somerset. The principle behind Solution 1 is that, above a certain air temperature, each power plant must reduce its power output in order to follow the guidelines of its permit. The solution addresses the environmental requirements by strictly obeying the permit limitations. Dial-back occurs slowly in this scenario. The use of an air-temperature related fee increase may serve to reduce consumer demand, and it would allow the power plant recoup lost revenue associated with dial-back.

Solution 1 Description

The MLR equations for Cleary-Flood (Equation 14) and Somerset (Equation 26), which are reproduced below, show that if the maximum instantaneous discharge temperature is held constant and the average daily high air temperature rises, the net energy generation must fall.

$$T_{max}^{001} = 11.667 + 0.689(A_{CF}) + 6.977(\log_{10} G_{CF}) \tag{14}$$

$$T_{max}^{007} = 26.178 + .830(A_S) + .0001(G_S) \tag{26}$$

The following figures demonstrate the relationship between rising air temperatures and potential monthly generation as well as the impact on retail prices if prices varied as a function of declining output capacity.

Both figures show monthly average of daily high air temperature on the x-axis and two y-axes: potential net energy generation of the operating unit on the left y-axis and retail prices on the right y-axis. The dashed lines show the monthly energy output that the power plants would expect to provide during the two hottest months of the year, July and August, for different average air temperatures, and if their thermal limitations were strictly followed.

On average, Cleary-Flood generates about 1,470 MWh of electrical energy per month out of Unit 8 during the hottest parts of the year. This corresponds to an average power output of 2.04 MW over the course of a month. On average, Somerset generates 70,372 MWh out of units 5 and 6 per month during the hottest months of the year, which equates to a power output of 96.3 MW.

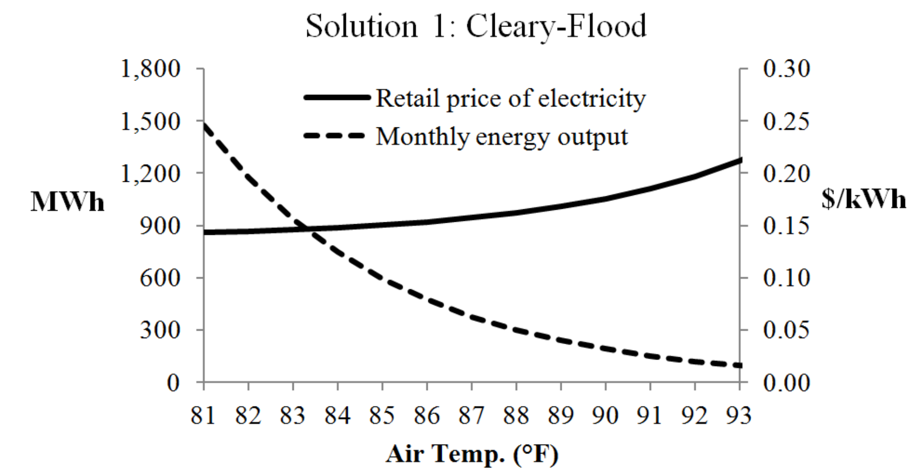
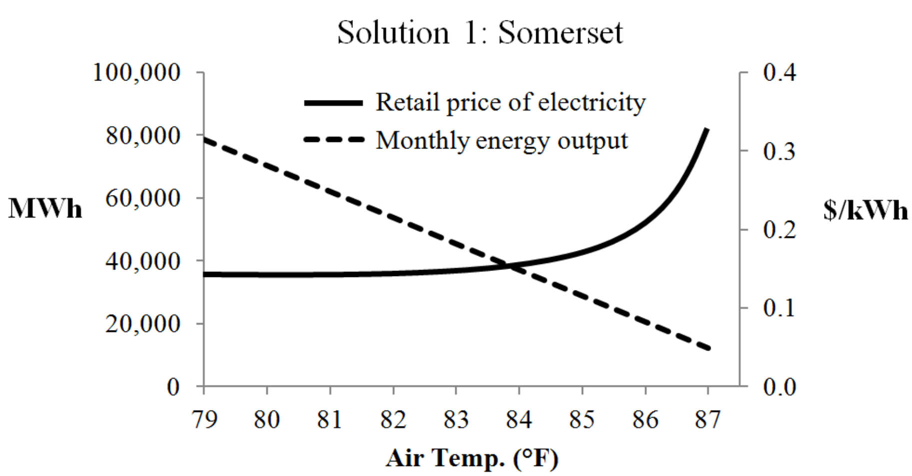


Figure 77. Model monthly energy generation and retail price of electricity versus monthly average of daily high air temperature at Cleary-Flood in Solution 1.

Figure 78. Model monthly energy generation and retail price of electricity versus monthly average daily high air temperature at Somerset in Solution 1.



The solid line illustrates the effect of increasing fees as a function of the decline in potential output capacity. The fees would allow the power plants to recoup losses associated with dialing back their generation as a means of encouraging facility managers to strictly follow their NPDES temperature limitations. In some cases, the increased prices may also have the effect of lowering demand.

For Cleary-Flood, according to Figure 77, at an average air temperature of approximately 81°F, the power plant begins to face its thermal effluent limitation of 90°F. Net energy generation declines and is near zero at an air temperature of 93°F.

Figure 77. Model monthly energy generation and retail price of electricity versus monthly average of daily high air temperature at Cleary-Flood in Solution 1. Figure 77 also shows the effect on retail prices if a “hot weather fee” were in place. The fee would appear at the same moment that generation begins to decrease—an air temperature of 81°F.

At 86°F, the retail price per kilowatt hour has increased to a modest $0.1532—still below the average price paid by electricity consumers in Massachusetts in 2010, $0.1633/kWh (Eisenbach Consulting, 2010). At an air temperature of 93°F, the retail price per kilowatt·hour is roughly $0.21.

Somerset shows a similar situation, but over a slightly different range of temperatures and with a different cost structure. Figure 78 shows that the energy generation at Somerset would begin to decline at an air temperature of about 79°F, with a linear decline as air temperature decreases, assuming that the power plant operators do not greatly modify the cooling water flow-through rate.

For Somerset, for a monthly average of daily high air temperatures at 86°F, the retail price would be around $0.20/kWh. Complete shutdown is expected to occur when daily high air temperatures consistently reach higher than about 87°F or more.

Solution 1 Analysis

The major benefit of this and the following solutions is that permit compliance is held at a premium. No violations occur. Additionally, dial-back occurs gradually, rather than suddenly, which has benefits to consumers and utilities in the form of reducing the likelihood of unexpected supply interruptions and load changes (e.g. blackouts, brownouts).

The most obvious shortcoming of this approach is that the operating units are not able to supply electricity to fully meet demand. There may also be ethical problems with charging very high premiums for energy on very hot days, to the extent that low income populations would bear a disproportionate burden if fees were noticeably higher.

It may be an oversimplification to analyze the facility at such a time scale, but one might also argue that such oversimplifications are a central and necessary component of NPDES permitting of once-through cooling systems in general. Further, the time scale of these solutions matches the timescale of the regulatory challenges they are attempting to fix.

To summarize, Solution 1 provides a situation in which the environment is protected and sudden dial-back is avoided. It only partially meets the requirement that supply out of each generation unit meets demand.

Solution 2 Introduction

Solution 2 relies on the principle that, all other things being equal, it is possible to maintain the same level of electrical output from a given generating unit even under conditions of increasing ambient air temperatures by increasing the flow through the cooling system instead of allowing the effluent temperature (*ΔT*) to increase. This trade-off follows the relationship first presented as Equation 3 in Chapter 3. It is repeated here:

$$C = \frac{\Delta T q e}{6823(1-e)} \qquad (3)$$

where C is the capacity in MW, q is the cooling water flow rate in gallons per minute, ΔT is the rise of the cooling water temperature between the intake and the outfall in F°, and e is the thermodynamic efficiency of the facility.

For the purposes of relating the preceding equation to the MLR equations and ambient air temperature specifically, it was necessary to assume that water temperature follows air temperature linearly, according to the following equation (Stefan and Preud’Homme, 1993):

$$T_w = 37.22 + 0.86(T_a - 32)$$

Equation 32. Generalized linear relationship between air and water temperature (adapted from Stefan and Preud'Homme, 1993).

T_w is the temperature of the water in °F and T_a is the temperature of the air. As Stefan and Preud'Homme (1993) note, actual conditions for any particular stream or river can differ substantially, and there are more precise ways of expressing the relationship. Still, it is used because it allows for a basic theoretical discussion about how to combine Solutions 1 and 2.

Increasing the withdrawal rate in order to compensate for decreases in the potential temperature rise through the condenser benefits the environment, as long as both the temperature and withdrawal rate limitations are followed. Electricity supply remains equal to demand under higher temperature regimes. When both the temperature and withdrawal rate limitations are reached, abrupt dial-back would occur.

Solution 2 Description

In order to apply this concept to both of the case study plants, it was assumed that each of the generating units has a thermal efficiency of 0.35, which means that for every 100 joules of thermal energy produced at the facility, 35 joules of electrical energy are produced. A thermal efficiency of 0.35 may be generous for such old plants, but they are nonetheless likely to fall within a range between 0.30-0.40 (Schilling, 2008).[3]

Figure 79 and Figure 80 show what this means in practical terms for an output of 2.04 MW and 96.3 MW at Cleary-Flood and Somerset, respectively. Here again, the dashed line shows potential monthly energy generation during summer months, while the solid line shows the change in retail price as a function of lost output potential. Each power plant is neither gradually dialing-back its generation, nor charging additional fees, so both values are constant until they abruptly stop at a specific air temperature.

The cut-off for showing where the limiting threshold is located was chosen for a ΔT of 1F°, because at a ΔT of 0F°, Equation 3 is undefined (i.e., flow-through would have to be infinitely high to carry away the waste heat).

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[3] For a fuller explanation of how thermal efficiency would be calculated for these and other power plants, see *Power plant engineering*, by Drbal et al., 1996, p. 170.

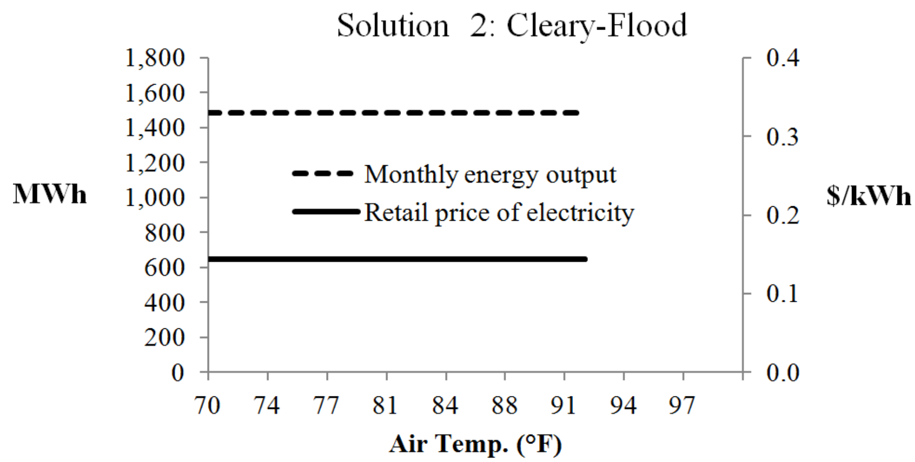
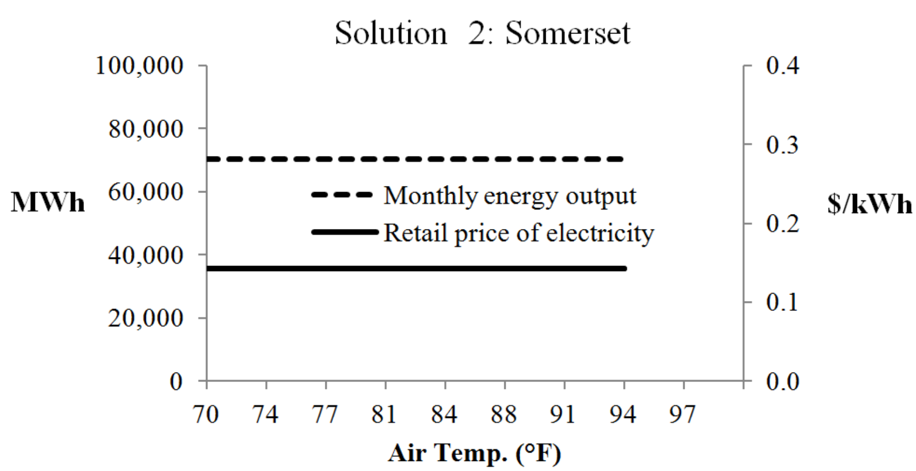


Figure 79. Model monthly energy generation and retail price of electricity versus monthly average daily high air temperature at Cleary-Flood in Solution 2.

Figure 80. Model monthly energy generation and retail price of electricity versus monthly average daily high air temperature at Somerset in Solution 2.



Solution 2 Analysis

It is clear from Figure 80 that Somerset can operate at full summer capacity while still abiding by its temperature and withdrawal limitations even when ambient air temperatures are very high (up to 95°F). Likewise, Cleary-Flood can be expected to operate normally during months when the average daily high air temperature is at or below 92°F. When daily high air temperatures consistently reach 92°F, flow would be expected to reach about 60 cfs. Incidentally, this value is not far from the 55.7 cfs *maximum* flow-in-conduit limitation that is part of Cleary-Flood's NPDES permit. It is much higher than the 8.97 cfs *average* withdrawal limitation that the facility must abide by during the summer. On the other hand, Somerset would not reach a temperature barrier until its withdrawal rate is about 600 cfs and at an air temperature of nearly 105°F, or almost double its maximum allowable flow-in-conduit limit of 309 cfs, and nearly three times its monthly average flow limitation of 220 cfs. Figure 80 shows the point of sudden dial-back occurring when the maximum flow-in-conduit limitation is reached, rather than when the ΔT value is expected to reach zero.

Solution 2 has advantages and disadvantages that are distinct from those presented in Solution 1. The first advantage is that the environment is protected from negative thermal impacts and impacts associated with high volume withdrawals (i.e., the power plant abides by its permit). The second advantage is that consumer demand for electricity would be met all the way to the point of rapid dial-back for each of the two units, so a scenario in which demands on each generating unit are greater than supply is further delayed.

Solution 2 has one major disadvantage: the thermal limitations and flow limitations would surely be reached if air temperatures rise above a certain level. This amounts to the sudden dial-back that the solutions are trying to avoid and which are distasteful to power plant operators, fish, and consumers alike.

There is another response that combines some of the principles outlined in the two previous scenarios, and it is presented in the following section as Solution 3.

Solution 3 Introduction

Solution 3 is a hybrid approach in which dial-back occurs only after the maximum allowable withdrawal limitations are reached.

The theory is that, once ambient temperatures become hot enough, the power plant operator increases flow through the plant until the withdrawal rates equal the limitation, after which dial-back occurs. Here, the average allowable flow-in-conduit is used as the point at which dial-back begins, rather than the maximum flow in conduit limitation that Solution 2 follows. As with the other solutions, compliance with the NPDES permit as a proxy for environmental protection is strictly followed.

Scenario 3 Description

Instead of initiating a gradual dial-back at each of the two power plants at the air temperature thresholds outlined in Solution 1—81°F for Cleary-Flood and 79°F for Somerset—the withdrawal rate is increased. When the withdrawal rate reaches the average allowable withdrawal rate for Cleary-Flood and Somerset (i.e., 8.97 cfs and 220, respectively), gradual dial-back occurs and the "hot weather fee" schedule is used.

Figure 81 and Figure 82 show the effect on potential monthly energy output (dashed line) and the effect on retail electricity prices (solid line). Monthly average of daily high air temperatures are shown on the x-axis. Potential energy generation in MWh is shown on the left y-axis, while retail price of electricity in dollars per kWh is shown on the right y-axis.

Solution 3 Analysis

Figure 81 illustrates how the net monthly energy generation for Cleary-Flood Unit 8 responds to the combined approach. At an air temperature of 82°F, the plant operators would slowly increase flow through the cooling system. At an intake water temperature of 85°F, they would slowly decrease generation until the water temperature at the intake was 90°F (i.e., $\Delta T = 0$). Again, when the intake water temperature reaches 90°F, it is thermodynamically impossible for the power plant to generate electricity. An ambient water temperature of 90°F roughly corresponds to an ambient air temperature of 92°F.

Because energy output is a function of both the temperature rise through the condenser and the withdrawal rate, the flow continues to change as dial-back occurs and as the ΔT approaches zero. Flow reaches its maximum at 14.37 cfs when monthly energy generation would be near to 400 MWh and $\Delta T = 1$.

Figure 81 also shows how retail prices might respond. Again, the managers would increase flow at an air temperature of 82°F. At an intake water temperature of about 85°F, the fees would appear, recouping revenue losses at the facility associated with dial-back and potentially reducing consumer demand. At an air temperature of about 92°F, customers are paying about $0.15/kWh for their electricity, which is less than the $0.1851/kWh that they would be paying with the fee schedule outlined in Solution 1, and only moderately higher than that paid in Solution 2.

By the time Cleary-Flood can no longer produce power out of Unit 6, incremental power outages have already occurred, so that the complete shutdown does not occur all at once, impacting all consumers simultaneously.

Figure 82 tests the same theory for Somerset. Monthly energy generation is steady even after the 79°F threshold is reached as a result of increasing withdrawals. At an air temperature of about 90°F, the flow has nearly reached its permitted limit for average flow-in-conduit of 220 cfs, at which point the operators would begin to decrease the power output and charge the corresponding fee.

Figure 82 also shows how retail electricity prices might be affected if the "hot weather fee" schedule were in place. It also highlights a peculiarity about Somerset's maximum discharge temperature model: generation is expected to reach zero *before* the

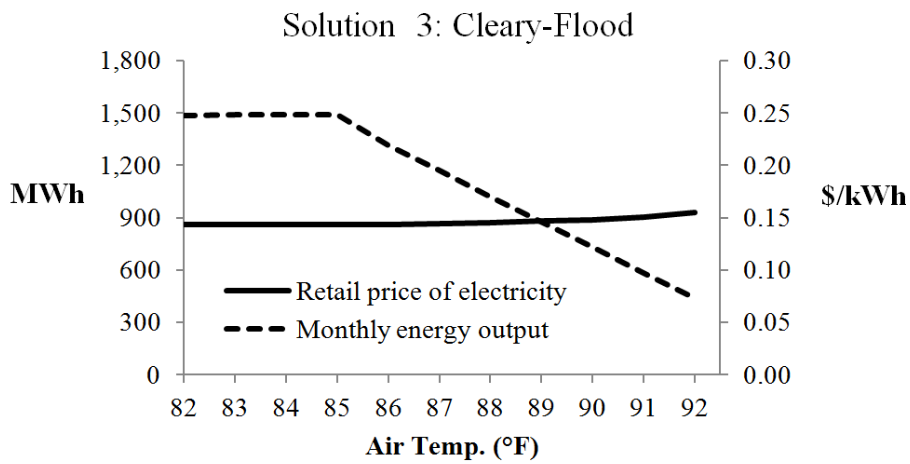
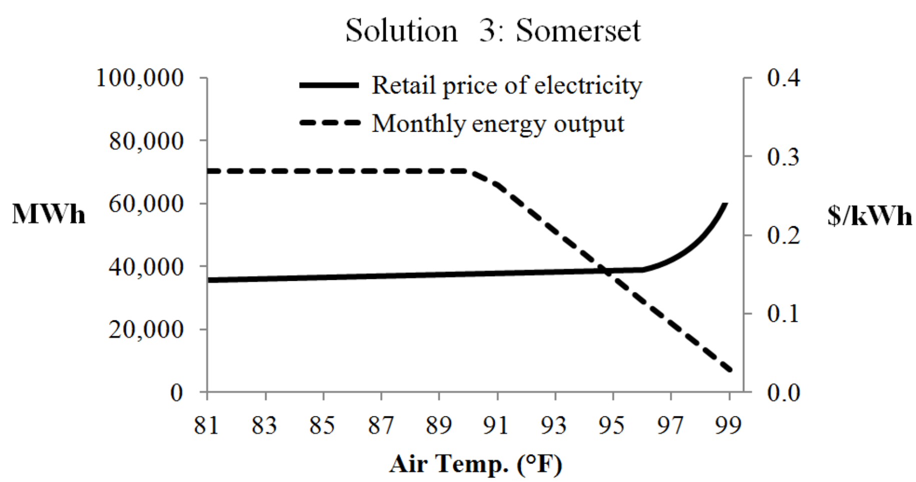


Figure 81. Model monthly energy generation and retail price of electricity versus monthly average daily high air temperature at Cleary-Flood in Scenario 3.

Figure 82. Model monthly energy generation and retail price of electricity versus monthly average daily high air temperature at Somerset in Scenario 3.



ΔT between the intake water temperature and the discharge temperature reaches zero (i.e., at an ambient water temperature of 100°F). One possible reason is that other systems begin to negatively impact generation for Unit 6 once ambient air temperatures consistently reach the high 90s.

Solution 3 shows one obvious advantage for consumers and utility managers: demand would not exceed supply for Cleary-Flood and Somerset until the ambient air temperature consistently reached 85°F and 89°F, respectively. An additional advantage of Solution 3 is that dial-back is gradual, which give customers, utilities, power plant managers, and fish additional time to adjust to change. Most importantly, though, the NPDES thermal and withdrawal limitations are not violated.

Modification of Solution 3

In all cases, Solution 3 appears to be the preferred option but it requires additional modification to capture, or at least elicit, basic economic laws of supply and demand. In the real world, both the facility and the consumer adjust their actions to cope with new operating conditions. Behavior of each facility influences the behavior of consumers and vice versa. In *Supply and Demand*, H. Henderson provides the three fundamental laws of economic theory (Henderson, 1922):

1. At a given market price, when demand is greater than supply, the price will tend to rise. Conversely, if supply exceeds demand, the price will tend to fall.
2. A rise in price tends to decrease demand and increase supply. A fall in price tends to increase demand and decrease supply.

3. Price will tend to move to the point at which supply and demand are equal (i.e., the equilibrium price).

If the total supply of electricity equals the total demand of electricity at each power plant at any given time, a rise in the price according to a hot weather fee schedule will serve to decrease demand. The decrease in demand would mean that a greater percentage of the consumer demand can be met, even during months when the power plant must dial back its power output.

Demand elasticity plays a significant role in determining the efficacy of using price increases to influence environmental compliance by the power plants. Very elastic demand would mean that consumers greatly modify their behavior in response to higher electricity prices. Very often, however, electricity demand can be somewhat inelastic for residential consumers. Customers see the price of their electricity at the end of the month when they see their bill, and only after they have used the electricity. Their behavior is likely to change only if they knew that 1) the following month's prices would be higher, 2) the prices were linked to hot weather, and 3) the prices were substantially higher on the hottest days.

At present, the most obvious behavioral response is between ambient air temperature and air conditioner use. People turn their air conditioners on when ambient air temperatures are consistently high. Likewise, a family may decide to always keep its thermostat set to 75°F, which means that greater electricity is needed on hotter days to maintain their level of comfort, even if there is no ongoing behavioral response on the part of the family. A regulatory system could be designed to promote a response that counters the inclination to use more electricity on hotter days.

A substantial shortcoming to the current system of price communication between power plants and consumers is the lag between providing electricity and paying for it. Consumers would be better able to modify their behavior for their own benefit and the benefit of the electricity providers if they knew exactly how much they were paying for electricity each day (Kirschen et al., 2000). The method of communicating price signals might be as low-tech as a fact sheet provided by the utility showing prices for each day of the month or as advanced as a thermostat that shows the price per kWh in real time and showing the monthly bill as it accrues. With more accurate information, consumers could play a large role in easing the burdens on power plant operations and may have an easier time looking for alternative cooling methods on hot days (e.g. fans, misters, shaded parks, public air-conditioned spaces).

At present, price determinants are fairly hidden from electricity consumers. Based on the previous discussion, it is reasonable to say that prices would more accurately reflect their true equilibrium point if consumers were better equipped to respond to price changes and if prices were appreciably high.

Current electricity pricing schemes often fail to account for costs that are external to power plant operations, such as ecosystem damages. Power plants and consumers have both had a part in damaging the environment, so it would also be reasonable to shift some of the burden of the proposed costs from consumers, who are paying higher prices in the Solution 3 scenario, to the power plants themselves. Profit margins would no doubt be negatively affected in the short run, but the power supply would be more reliable and the downstream ecosystem would be healthier—both of which are public goods. To demonstrate this in the model, power plants and consumers share the new financial burdens of environmental protection in a 50-50 ratio.

The net effect of the preceding modifications is that a greater percentage of the total electricity demand by consumers is likely to be met, and downstream aquatic habitats will be protected.

Solution summary

Table 33 presents a summary of the results of each of the solutions. For each solution, it shows the air temperature at which withdrawal rates begin to rise, the point at which retail electricity prices begin to rise, the final air temperature at which the power plant is operational, and the highest theoretical retail price paid by consumers in each scenario. In all cases, no permit violations occur.

Solution 3, as modified by a fuller explanation of economic effects, shows that it is a preferred option. The major difference between final prices shown for Solution 3 and Solution 3 (modified), is that prices in the modified version of Solution 3 represent cost-sharing between power plants and consumers in a 50/50 ratio. The approximation symbol (≈) indicates that the actual retail prices may be influenced by changes in demand and supply as a result of the proposed fee schedule.

The precise regulatory mechanism for deploying any one of these solutions is an important point that is left up to state and federal policymakers. The purpose of the analysis shown here is simply to highlight the various ways in which the problems associated with high ambient temperatures can be mitigated with corrective actions. It is not an attempt to present the full breadth and depth of possible solutions or to disparage the men and women at Cleary-Flood and Somerset who work hard to provide consumers with electricity and to do so with minimal damage to the environment.

Table 33. Summary of the effect of each solution on various aspects of each power plant's monthly generation and retail price of electricity provided.

	Solution 1	Solution 2	Solution 3	Solution 3 (modified)
Withdrawal rate begins to rise at…(°F)				
Cleary-Flood	Does not	81	81	81
Somerset	Does not	79	79	79
Retail price begins to rise at…(°F)				
Cleary-Flood	81	Does not	85	85
Somerset	79	Does not	90	90
Final air temp. plant is operational (°F)				
Cleary-Flood	93	92	92	92
Somerset	87	95	99	99
Final retail price ($/kWh)				
Cleary-Flood	0.22	0.14	0.15	≈ 0.15
Somerset	0.33	0.14	0.24	≈ 0.19

CHAPTER 8

CONCLUSIONS AND RECOMMENDATIONS

The hypothesis has been tested, and—within the scope of the model and its methodology—there are clear answers. The following paragraphs address each of the challenges presented by the original hypothesis; make the case that this methodology is transferable and can be scaled up to identify regional issues, and thereby outline opportunities for future work; and put this work within the context of the larger concerns of energy and water scientists and practitioners.

Revisiting the hypothesis

The first assertion of the hypothesis was that "Environmental variables and energy generation values can be used to estimate effluent temperature and water use rates at once-through cooled thermoelectric facilities." This statement is partly true and partly false. A truer statement would read, "Ambient air temperature and net energy generation values can be used to estimate the maximum monthly discharge temperature for the once-through cooled units at Cleary-Flood and Somerset."

Neither flow-in-conduit nor the temperature rise through the condenser were successfully modeled. Furthermore, a sweeping conclusion about all open-loop thermoelectric facilities in the U.S. would require a great deal more research involving a statistically significant and randomly selected sample of the total population of facilities.

The chapter on hindcasting demonstrated why the next point in the hypothesis is true: “Model generated effluent temperature and water use violations outnumber historical alleged violations.” With regard to the maximum effluent temperature violations only, model generated violations do outnumber historical alleged violations. This was true for a variety of reasons. First, the record of alleged violations is incomplete, and represents only about 5 years worth of operational data, whereas the time period available to test using the record of energy generation values and air temperature values spans decades. Predictions based on the successful multiple regression equations matched the observations very well, as the corresponding scatter plots show (Figure 53 and Figure 63). If the record of observations were more complete, not only would the regression models be stronger, it is very likely that power plant managers struggled to compensate for high ambient air temperatures during the hottest summers.

The second reason is that maximum monthly discharge temperatures are reported through NPDES, so there is no way of knowing precisely how much the power plant had to dial back to avoid violating its permit, on which days, or for how long. The third reason is that state and federal scrutiny is generally lacking for power plants of this age and type. Limited personnel and financial resources ensure that only the most egregious actual violations become “alleged violations,” and only a subset of those become official citations.

One view is that all of the environmental damage that could occur at older facilities has already occurred, so it makes sense to direct resources toward the prevention of new or additional environmental harm in other areas. Add this to the fact that the NPDES system is driven largely by self-reporting, and it is little wonder that the marsh destruction that occurred at Cleary-Flood (i.e., formation of the Discharge Creek) took fifty years to notice.

The final sentence in the hypothesis states that “Regulatory response mechanisms may be incorporated into a model of each facility-environment system to reduce both the number of predicted dial-back events (i.e., reduced capacity events) and the number of predicted permit violations.”

Each of the three solutions presented requires that the permit not be violated, so it is clear that the responses would "reduce...the number of predicted permit violations." Another approach may have been to allow marginal increases to the temperature of the effluent and to see how the price and generation respond, but such an approach would undermine the original intent of environmental protection.

Dial-back, on the other hand, is not prevented. In fact, it may occur even more frequently than it would have without explicit planning and "hot weather fees," but the undesirable effects of rapid derating (e.g. environmental, financial, and human health-related effects) would be mitigated. Dial-back would take no one by surprise, and it may spur further development of energy production technologies that can operate under extreme environmental conditions. Whatever the case, improved policies and procedures have been used in the past to deal with some of the negative effects of energy production, yet there is little reason to believe that the problems presented here have either already been fully addressed or are intractable.

Regional analysis

The original vision for this assessment was to identify the water-related risks to energy infrastructure in Massachusetts. More specifically, the first question considered was "Are power plants in Massachusetts likely to face problems in the future because of an inability (on the part of nature) to provide adequate water and suitable ambient temperatures?" With such a scope and with the resources available to do the analysis, the task was not feasible. Doing so may have been inadvisable, anyway, because preliminary research was still needed to identify the specific parameters that affect once-through power plants at a monthly level. Also needed were a survey of the existing databases and a close review of the specific environmental regulations by which the power plant managers are expected to abide.

The model performed well for the maximum monthly discharge temperature at the large base load facility, Somerset. The results for the same parameter at Cleary-Flood, a peak load facility, were slightly less impressive, but still useful. One conclusion is that the methodology would be most appropriate to use for large, once-through cooled thermoelectric facilities. The operational capabilities of the model are a function of the availability of long term air temperature data, long term generation data, and the availability of data on either monthly maximum discharge temperature, monthly average discharge temperature, or both. Specific permit limit values and location data are also needed.

An internal study by the USGS revealed that less than half of the permitted thermoelectric facilities that exist today appear within the EPA's ECHO database (i.e., the data resource used for this study) (T. Diehl, personal communication, September 26, 2011). It is unclear why such data gaps exist, but history suggests that there is a significant lack of communication between many states and federal environmental offices, especially on low priority topics.

Some data gaps are beginning to be addressed. USGS scientists also explained that the forthcoming EIA reporting requirements for large thermoelectric facilities ask power plant managers to provide intake and discharge temperatures for their once-through systems and *at a monthly time scale*. If the revised Form-923 survey is successful, statistical analysis of the form found within this research would be achievable within two years. Within five years, the statistical accuracy would be excellent. Two years worth of data would equate to 24 discharge/intake temperatures per power plant, and five years would provide 60 such data points per facility.

A recent Union of Concerned Scientists report verifies that changes to the EIA survey are coming, and that they are desperately needed (UCS, 2011). The same NCDC air temperature data and EIA energy generation data sets used in this analysis could be used in future work. Two additional obstacles to doing a rapid analysis at a national scale involve the availability of accurate location data and the availability of specific temperature limitations for each plant. Fairly accurate geographic information does exist, often proprietarily, but it is unclear if and when such data will become available to the general public or to academic scientists who want to study national electricity supply risks. Many permit limitations are published within the ECHO database, but a more time consuming search of specific records would probably be necessary for a comprehensive analysis. An assumption of a 90° F temperature limitation for effluents discharged into smaller rivers and a 100°F temperature limitation for coastal facilities would probably be a good first guess, but as this research has shown, the specific limitation is important to know.

An application of the current methodology at the national scale for all once-through facilities would serve to identify those facilities which are most in need of retirement. It would also offer some guidelines by which the aging fleet of once-through facilities might price their electricity in order to ease the transition into a more environmentally friendly energy future.

Larger context

High temperature, high flow effluents from once-through cooled facilities continue to do damage to our nation's waterways, but much of the damage may be reversible (Poornima, 2006). With corrective action, it is possible to avoid an environmental emergency exacerbated by climate change and growing energy demands.

By sitting down with so many knowledgeable individuals who work at the hub of the various spokes of water and energy challenges in the U.S., I can describe, with a greater degree of certainty, where this specific area of study ranks among the others. In short, it is a small part of what federal, state, non-profit, academic, and industry scientists see as the most pressing problem with the water-for-energy paradigm in which we find ourselves: power plant cooling. There is uncertainty about which areas of the U.S. will be impacted the hardest, though it is clear which areas will be impacted the soonest: Texas, California, Nevada, Arizona, New Mexico, Florida, and the Carolinas have already had substantial water shortages, and population growth in these areas continues to drive up water demands for municipal uses and electricity supply. To complicate matters, natural geographic variation in water and uncertainties involving energy supplies make the challenges faced extremely political.

There remains a great deal of disagreement about what the future of power plant cooling will look like, even at the most basic level. For instance, which type of cooling system will become the most popular in the decades to come (e.g. recirculating, air-cooled, hybrid)? There is also disagreement between the federal agencies whose mission areas relate to protecting energy and water supplies for future use. For example, the DOE, which is tasked with understanding risks to national energy security, has yet to take a firm stance on whether energy provisions in the U.S. are even at risk as a consequence of diminishing water supplies and increasing air temperatures in the face of climate change. That the DOE demurs on these issues is unsurprising given the inauspicious start to the first-ever Energy-Water Nexus Roadmap, which was mandated by the 2005 Energy Policy Act, but has never officially been released.

These deeper institutional issues are among the many other problems brought to light by the federal government's (and specifically Sandia National Labs') original investigation of the water constraints of power plants (US DOE, 2006). Other, important areas of potential future conflict involve the water requirements for biofuels, and the use of fresh and brackish water sources for the extraction and refinement of oil and gas resources, including the enormous water quality and quantity impacts that the emerging unconventional oil and natural gas industry has.

Ultimately, the potential for research in water-for-energy studies is quite high. There are countless unanswered questions, which by their nature and sheer number, indicate that we need to start accounting for our water supplies and aquatic ecosystems in an unprecedented way. There are so many uses for water other than energy production (e.g. agriculture, manufacturing), that we would be doing future generations a disservice by failing to treat it as the valuable and important resource that it is. The interaction between NPDES permitting and power plant operation need not be antagonistic. It is possible to create electricity in an environmentally responsible manner, but we need better science and regulations to do so.

To conclude, there are several straightforward recommendations that one can take away from this body of research:

1. When crafting state and federal legislation and regulations, energy policymakers should reflect on the constraints that environmental regulations impose on the reliability of the electricity provided by the aging fleet of once-through facilities.
2. Environmental managers should evaluate new and existing NPDES permits based on evidence of present harm in addition to the probability that future harm will occur in light of increasing ambient air temperatures, increasing electricity demands, and increasing streamflow volatility.

3. Federal and state energy and environmental officials should make full use of the data which already exist in order to recognize opportunities to retire generating units that no longer provide a net benefit to society.

4. Electricity prices should better reflect the costs which have historically been externalized to the environment.

5. Electricity and water data should be collected and aggregated with better precision and more frequently, and should be made available to resource scientists and practitioners.

APPENDIX A

TABLES

Table A1. NPDES parameters reported in DMRs for Cleary-Flood Outfall 001, Outfall 002, and Somerset Outfall 007.

Outfall	Year	Mo.	Avg. With. (cfs)	Max. With. (cfs)	Max. Temp. (°F)	Max ΔT (°F)	Source
CF 001	1994	8	15.16	16.9	90	17	MassDEP SERO
CF 001	1994	9	18.57	18.6	86	16	MassDEP SERO
CF 001	1994	11	12.84	19.6	72	22	MassDEP SERO
CF 001	1994	12	9.9	11.6	58	17	MassDEP SERO
CF 001	1995	1	9.44	12.5	64	12	MassDEP SERO
CF 001	1995	2	4.64	7.1	53	15	MassDEP SERO
CF 001	1995	3	8.97	12.4	52	15	MassDEP SERO
CF 001	1996	1	10.68	15.3	57	19	MassDEP SERO
CF 001	1996	2	15.94	26.6	60	16	MassDEP SERO
CF 001	1996	3	16.56	16.9	53	14	MassDEP SERO
CF 001	1996	5	15.01	22.3	76	8	MassDEP SERO
CF 001	1996	6	13.46	13.5	80	7	MassDEP SERO
CF 001	1996	7	19.34	28.6	87	22	MassDEP SERO
CF 001	1996	8	16.86	29.2	87	10	MassDEP SERO
CF 001	1996	9	12.38	18.1	76	7	MassDEP SERO
CF 001	1997	1	13.15	16.7	52	7.5	MassDEP SERO
CF 001	1997	4	11.29	11.3	56	8	MassDEP SERO
CF 001	1998	9	9.13	15.3	80	11	MassDEP SERO
CF 001	1998	12	11.45	20	59	19	MassDEP SERO
CF 001	1999	1	11.29	24.3	58	23	MassDEP SERO
CF 001	1999	2	14.54	14.5	50	12	MassDEP SERO
CF 001	1999	3	13.46	18.9	64	20	MassDEP SERO
CF 001	1999	4	7.12	7.1	66	10	MassDEP SERO
CF 001	1999	6	22.9	39.6	90	13	MassDEP SERO
CF 001	1999	7	24.6	44.9	90	12	MassDEP SERO
CF 001	2005	10		20.58	81	25	EPA ECHO
CF 001	2005	12		10.37	78	21	EPA ECHO
CF 001	2006	2	11.14	11.14	63	22	EPA ECHO
CF 001	2006	7	26.92	29.71	90	9.7	EPA ECHO
CF 001	2006	8	29.09	31.25	88	8.7	EPA ECHO

CF 001	2006	9	34.97	34.97	81	13.2	EPA ECHO
CF 001	2007	1	0.06	1.7	46	2	EPA ECHO
CF 001	2007	2	1.32	22.12	57	22	EPA ECHO
CF 001	2007	3	1.3	40.54	57	22.4	EPA ECHO
CF 001	2007	7	1.19	36.98	88	11.4	EPA ECHO
CF 001	2007	8	0.77	23.98	82	8	EPA ECHO
CF 001	2007	9	1.07	32.34	82	13.3	EPA ECHO
CF 001	2007	10	0.01	0.2	66		EPA ECHO
CF 001	2007	12	0.46	15.47	59	19	EPA ECHO
CF 001	2008	4	1.38	40.54	66	12	EPA ECHO
CF 001	2008	6	3.25	38.22	88	19	EPA ECHO
CF 001	2008	7	1.55	25.22	89	10.2	EPA ECHO
CF 001	2008	9	1.86	27.54	87	13	EPA ECHO
CF 001	2008	12	0.51	15.94	61	28	EPA ECHO
CF 001	2009	1	0.93	27.85	80	18	EPA ECHO
CF 001	2009	6	1.55	46.42	83	13	EPA ECHO
CF 001	2009	7	0.77	23.67	89	21	EPA ECHO
CF 001	2009	8	0.93	28.62	89	10	EPA ECHO
CF 001	2010	3	0.65	20.13	55	12	EPA ECHO
CF 001	2010	5	0.9	27.69	84	12	EPA ECHO
CF 001	2010	6	1.78	32.49	90	11	EPA ECHO
CF 001	2010	7	6.5	30.94	90	12	EPA ECHO
CF 001	2010	8	2.63	32.03	90	17	EPA ECHO
CF 001	2010	11	3.09	3.87	73	20	EPA ECHO
CF 001	2010	12	1.49	29.4	59	25	EPA ECHO
CF 002	1994	8	0.17	0.37	88		MassDEP SERO
CF 002	1994	9	0.14	0.18	86		MassDEP SERO
CF 002	1994	11	0.22	0.28	86		MassDEP SERO
CF 002	1994	12	0.23	0.32	85		MassDEP SERO
CF 002	1995	1	0.16	0.22	86		MassDEP SERO
CF 002	1995	2	0.09	0.19	100		MassDEP SERO
CF 002	1995	3	0.17	0.36	80		MassDEP SERO
CF 002	1996	1	0.29	0.65	45		MassDEP SERO
CF 002	1996	2	0.28	1.41	56		MassDEP SERO
CF 002	1996	3	0.14	0.19	48		MassDEP SERO
CF 002	1996	5	0.1	0.15	70		MassDEP SERO
CF 002	1996	6	0.07	0.12	76		MassDEP SERO
CF 002	1996	7	0.09	0.12	77		MassDEP SERO
CF 002	1996	8	0.16	0.26	90		MassDEP SERO

CF 002	1996	9	0.16	0.23	90		MassDEP SERO
CF 002	1996	10	0.18	0.28	78		MassDEP SERO
CF 002	1996	12	0.05	0.14	84		MassDEP SERO
CF 002	1997	1	0.21	0.2	78		MassDEP SERO
CF 002	1997	2	0.13	0.15	72		MassDEP SERO
CF 002	1997	3	0.14	0.15	76		MassDEP SERO
CF 002	1997	4	0.13	0.23	80		MassDEP SERO
CF 002	1997	5	0.12	0.2	76		MassDEP SERO
CF 002	1998	9	0.13	0.2	85		MassDEP SERO
CF 002	1998	12	0.21	0.43	88		MassDEP SERO
CF 002	1999	1	0.23	0.34	75		MassDEP SERO
CF 002	1999	2	0.18	0.26	78		MassDEP SERO
CF 002	1999	3	0.13	0.2	84		MassDEP SERO
CF 002	1999	4	0.14	0.31	80		MassDEP SERO
CF 002	1999	5	0.11	0.22	84		MassDEP SERO
CF 002	1999	6	0.15	0.42	86		MassDEP SERO
CF 002	1999	7	0.14	0.23	85		MassDEP SERO
CF 002	2005	10	0	0.11	90		EPA ECHO
CF 002	2005	11	0	0.15	86		EPA ECHO
CF 002	2005	12	0	0.11	84		EPA ECHO
CF 002	2006	1	0.1	0.3	83		EPA ECHO
CF 002	2006	2	0.09	0.14	78		EPA ECHO
CF 002	2006	3	0.1	0.14	80		EPA ECHO
CF 002	2006	5	0.08	0.2	86		EPA ECHO
CF 002	2006	6	0.1	0.23	85		EPA ECHO
CF 002	2006	7	0.19	0.46	100		EPA ECHO
CF 002	2006	8	0.13	0.94	103		EPA ECHO
CF 002	2006	9	0.06	0.11	100		EPA ECHO
CF 002	2006	11	0.1	0.15	78		EPA ECHO
CF 002	2006	12	0.1	0.12	88		EPA ECHO
CF 002	2007	1	0.11	0.11	86		EPA ECHO
CF 002	2007	2	0.09	0.2	79		EPA ECHO
CF 002	2007	3	0.13	0.11	88		EPA ECHO
CF 002	2007	4	0.05	0.13	94		EPA ECHO
CF 002	2007	7	0.13	0.67	99		EPA ECHO
CF 002	2007	8	0.18	0.59	100		EPA ECHO
CF 002	2007	9	0.15	0.59	100		EPA ECHO
CF 002	2007	10	0.12	0.3	98		EPA ECHO
CF 002	2007	12	0.2	0.56	98		EPA ECHO

CF 002	2008	1	0.08	0.19	92		EPA ECHO
CF 002	2008	2	0.07	0.13	83		EPA ECHO
CF 002	2008	3	0.09	0.15	86		EPA ECHO
CF 002	2008	4	0.07	0.12	91		EPA ECHO
CF 002	2008	5	0.09	0.19	88		EPA ECHO
CF 002	2008	6	0.18	0.52	97		EPA ECHO
CF 002	2008	7	0.24	0.82	100		EPA ECHO
CF 002	2008	8	0.13	0.39	100		EPA ECHO
CF 002	2008	9	0.12	0.4	100		EPA ECHO
CF 002	2008	12	0.19	0.1	88		EPA ECHO
CF 002	2009	1	0.1	0.15	87		EPA ECHO
CF 002	2009	3	0.1	0.14	94		EPA ECHO
CF 002	2009	6	0.1	0.37	93		EPA ECHO
CF 002	2009	7	0.09	0.28	98		EPA ECHO
CF 002	2009	8	0.21	1.14	100		EPA ECHO
CF 002	2009	10	0.08	0.24	90		EPA ECHO
CF 002	2009	11	0.06	0.16	78		EPA ECHO
CF 002	2009	12	0.07	0.14	91		EPA ECHO
CF 002	2010	1	0.08	0.09	88		EPA ECHO
CF 002	2010	3	0.09	0.37	69		EPA ECHO
CF 002	2010	5	0.14	0.53	94		EPA ECHO
CF 002	2010	6	0.21	1.32	100		EPA ECHO
CF 002	2010	7	0.25	0.8	90		EPA ECHO
CF 002	2010	8	0.13	0.48	100		EPA ECHO
CF 002	2010	9	0.12	0.32	100		EPA ECHO
CF 002	2010	10	0.06	0.17	91		EPA ECHO
CF 002	2010	11	0.07	0.25	91.5		EPA ECHO
CF 002	2010	12	0.06	0.11	92.5		EPA ECHO
S 007	2005	10		126.994	91		EPA ECHO
S 007	2005	11		162.27	75		EPA ECHO
S 007	2005	12		126.994	70		EPA ECHO
S 007	2006	1	126.99	126.994	63	22	EPA ECHO
S 007	2006	2	126.99	126.994	63	23	EPA ECHO
S 007	2006	3	121.38	126.994	66	23	EPA ECHO
S 007	2006	4	119.24	126.994	73	21	EPA ECHO
S 007	2006	5	126.99	126.994	80	19	EPA ECHO
S 007	2006	6	126.99	126.994	85	18	EPA ECHO
S 007	2006	7	154.67	171.554	96	20	EPA ECHO
S 007	2006	8	137.02	171.554	97	20	EPA ECHO

S 007	2006	9	120.73	126.994	91	22	EPA ECHO
S 007	2006	10	80.58	126.994	89	25	EPA ECHO
S 007	2006	11	121.39	126.994	81	24	EPA ECHO
S 007	2006	12	125.37	126.994	78	22	EPA ECHO
S 007	2007	1	118.89	126.994	67	22	EPA ECHO
S 007	2007	2	121.25	171.554	60	23	EPA ECHO
S 007	2007	3	121.42	126.994	68	23	EPA ECHO
S 007	2007	4	101.05	126.994	72	24	EPA ECHO
S 007	2007	5	126.99	126.994	87	22	EPA ECHO
S 007	2007	6	130.4	171.554	95	22	EPA ECHO
S 007	2007	7	148.76	171.554	98	20	EPA ECHO
S 007	2007	8	137.5	171.554	99	19	EPA ECHO
S 007	2007	9	134.92	171.554	97	22	EPA ECHO
S 007	2007	10	105.83	126.994	91	22	EPA ECHO
S 007	2007	11	146.3	171.554	81	23	EPA ECHO
S 007	2007	12	127.71	149.274	68	22	EPA ECHO
S 007	2008	1	132.33	171.554	65	23	EPA ECHO
S 007	2008	2	127.32	136.277	60	23	EPA ECHO
S 007	2008	3	128.02	160.414	68	23	EPA ECHO
S 007	2008	4	120.64	171.554	74	24	EPA ECHO
S 007	2008	5	126.99	126.994	86	22	EPA ECHO
S 007	2008	6	125.62	126.994	95	22	EPA ECHO
S 007	2008	7	163.69	171.554	99	19	EPA ECHO
S 007	2008	8	143.78	171.554	98	23	EPA ECHO
S 007	2008	9	88.84	145.561	95	22	EPA ECHO
S 007	2008	10	109.36	126.994	76	10	EPA ECHO
S 007	2008	11	115.65	126.994	76	22	EPA ECHO
S 007	2008	12	109.28	136.277	63	21	EPA ECHO
S 007	2009	1	121.24	126.994	59	22	EPA ECHO
S 007	2009	2	111.12	126.994	55	20	EPA ECHO
S 007	2009	3	79.37	126.994	58	19	EPA ECHO
S 007	2009	6	120.65	126.994	86	22	EPA ECHO
S 007	2009	7	98.66	145.561	95	23	EPA ECHO
S 007	2009	8	105.23	171.554	96	23	EPA ECHO
S 007	2009	10	100.13	105.828	78	18	EPA ECHO
S 007	2009	12	104.78	126.994	63	21	EPA ECHO

Table A2. Explanatory variables including average daily high air temperature, average daily streamflow, and monthly net electricity generation used in MLR analyses and hindcasting.

		Avg. Daily High Temp (°F)		Avg. Daily Streamflow (cfs)		Electricity Generation (MWh)		
Year	Mo.	C-F	Som	C-F	Som	C-F (Unit 8)	C-F (Unit 9)	Som (5+6)
1970	1	28.22	28.07	999.76	1,446.26	12,770		166,633
1970	2	39.53	39.32	2,008.97	2,906.17	9,807		158,450
1970	3	42.28	42.17	985.77	1,426.01	11,471		203,327
1970	4	56.68	56.59	1,460.38	2,112.59	11,126		179,883
1970	5	66.57	66.55	654.82	947.26	11,225		175,230
1970	6	72.98	73.19	420.82	608.76	11,894		144,954
1970	7	80.56	80.79	161.59	233.76	8,409		128,322
1970	8	80.02	80.28	105.78	153.03	12,116		134,278
1970	9	71.56	71.86	82.87	119.88	11,232		120,463
1970	10	62.88	63.09	128.05	185.23	12,268		123,347
1970	11	51.71	51.90	394.26	570.34	11,184		139,081
1970	12	36.67	36.59	494.09	714.75	12,485		149,110
1971	1	32.15	32.13	486.76	704.14	12,689		155,792
1971	2	37.83	37.87	1,193.95	1,727.16	11,247		134,406
1971	3	44.46	44.49	1,508.59	2,182.34	12,929		154,546
1971	4	54.05	54.35	817.89	1,183.16	11,915		107,685
1971	5	65.09	65.34	884.22	1,279.12	13,233		117,748
1971	6	77.36	77.61	259.98	376.09	11,952		133,382
1971	7	81.61	81.89	77.26	111.77	5,625		109,358
1971	8	80.93	81.24	68.53	99.14	12,049		132,323
1971	9	75.73	76.13	69.65	100.76	12,751		135,438
1971	10	67.20	67.62	110.02	159.16	14,013		161,576
1971	11	48.67	48.71	201.06	290.86	13,065		228
1971	12	42.97	43.13	371.20	536.98	13,850		153,558
1972	1	40.34	40.46	581.19	840.74	13,984		149,444
1972	2	37.84	37.55	767.97	1,110.95	13,139		180,941
1972	3	44.14	44.23	2,172.28	3,142.42	13,549		168,884
1972	4	54.06	54.18	996.05	1,440.89	12,750		145,777
1972	5	68.62	68.64	1,286.44	1,860.97	14,028		150,041
1972	6	73.82	73.58	1,353.07	1,957.36	12,051		140,080
1972	7	82.32	81.88	467.61	676.45	6,630		115,539
1972	8	80.09	80.07	261.52	378.31	12,392		128,549
1972	9	74.06	74.19	435.64	630.20	12,509		117,773

1972	10	59.28	59.48	454.53	657.53	13,454		151,750
1972	11	47.41	47.66	1,501.21	2,171.65	12,492		155,190
1972	12	41.65	41.65	2,063.40	2,984.92	13,559		168,343
1973	1	40.29	40.38	1,274.09	1,843.10	13,008		174,657
1973	2	38.62	38.31	1,304.30	1,886.81	12,159		176,769
1973	3	51.81	52.05	848.79	1,227.86	13,024		164,854
1973	4	60.37	59.99	1,262.18	1,825.87	11,181		118,426
1973	5	67.29	67.07	994.25	1,438.28	10,292		112,117
1973	6	79.64	79.22	404.23	584.76	10,200		123,550
1973	7	82.34	81.59	543.09	785.64	6,086		140,947
1973	8	83.73	83.10	303.09	438.45	10,864		148,953
1973	9	73.57	73.13	413.97	598.84	9,165		130,293
1973	10	64.00	63.89	253.60	366.86	10,666		154,090
1973	11	51.29	51.00	369.47	534.47	9,607		137,800
1973	12	46.62	47.01	1,518.37	2,196.48	4,385		145,096
1974	1	39.25	39.76	1,255.15	1,815.71	8,498		171,121
1974	2	37.91	37.80	1,127.72	1,631.36	9,191		177,939
1974	3	48.81	48.32	1,161.44	1,680.14	9,779		171,780
1974	4	60.73	60.17	1,270.98	1,838.60	8,293		148,139
1974	5	65.56	64.72	704.97	1,019.81	9,726		124,304
1974	6	75.93	74.75	329.07	476.03	8,007		127,573
1974	7	82.95	82.27	148.17	214.34	6,235		128,371
1974	8	83.29	83.80	120.18	173.86	13,214		73,694
1974	9	73.07	73.65	261.30	377.99	9,825		115,972
1974	10	60.21	60.49	378.63	547.73	10,827		135,554
1974	11	52.42	53.06	369.42	534.41	11,051		121,875
1974	12	42.90	43.09	886.84	1,282.91	10,572		121,817
1975	1	41.20	41.50	1,438.27	2,080.60	11,126		135,231
1975	2	39.01	38.67	993.85	1,437.70	10,819		120,321
1975	3	45.29	44.71	1,132.93	1,638.90	11,347		119,940
1975	4	54.86	53.94	1,101.67	1,593.68	10,326		102,631
1975	5	72.47	71.12	441.14	638.15	11,244		82,195
1975	6	75.94	75.08	423.36	612.44	10,073		88,170
1975	7	83.74	82.61	145.40	210.33	7,424		103,099
1975	8	80.80	80.22	147.58	213.49	10,926		105,229
1975	9	70.40	69.88	293.81	425.03	16,915		66,014
1975	10	65.38	64.95	803.35	1,162.13	25,903		67,525
1975	11	57.83	57.77	1,298.56	1,878.50	5,962		76,775
1975	12	41.25	41.35	1,219.14	1,763.61	60,953		86,937

1976	1	34.62	34.62	1,761.49	2,548.18	70,143	0	77,718
1976	2	46.52	46.13	1,525.53	2,206.84	46,716	0	48,699
1976	3	48.65	48.11	1,036.28	1,499.08	17,334	0	51,249
1976	4	64.36	63.56	681.82	986.33	12,581	0	50,251
1976	5	69.32	68.04	558.57	808.02	30,860	0	53,383
1976	6	80.88	79.91	154.28	223.18	30,886	0	50,666
1976	7	81.89	80.97	109.38	158.23	21,100	0	63,379
1976	8	80.58	80.25	528.87	765.07	11,097	0	41,634
1976	9	73.07	72.61	217.12	314.08	65	19,319	45,869
1976	10	58.81	58.54	542.19	784.33	4,387	1,254	57,205
1976	11	47.57	47.48	352.11	509.36	3,438	16,570	58,194
1976	12	36.64	37.28	357.77	517.56	937	36,314	67,373
1977	1	30.33	30.56	511.45	739.86	8,496	34,107	70,740
1977	2	37.68	37.32	661.35	956.71	7,720	2,092	54,449
1977	3	52.87	52.64	2,274.12	3,289.75	7,493	1,440	63,729
1977	4	62.00	62.01	1,180.45	1,707.64	6,007	9,082	14,265
1977	5	72.68	72.31	807.70	1,168.42	1,961	16,745	20,179
1977	6	75.77	75.62	625.97	905.52	3,979	23,029	47,898
1977	7	83.89	83.72	234.32	338.96	5,029	26,779	64,154
1977	8	82.55	82.28	180.99	261.82	3,088	22,341	45,958
1977	9	72.09	72.32	285.44	412.92	1,094	10,258	48,390
1977	10	61.89	62.35	1,079.79	1,562.03	1,483	192	74,058
1977	11	53.56	54.02	961.53	1,390.95	462	0	68,815
1977	12	39.89	40.51	1,474.86	2,133.53	1,481	0	85,278
1978	1	35.13	34.70	1,901.80	2,751.15	1,823	0	80,768
1978	2	33.31	32.67	998.12	1,443.89	1,057	0	72,062
1978	3	44.08	43.27	1,670.19	2,416.10	34	340	75,149
1978	4	56.38	55.96	1,523.24	2,203.52	1,069	26,901	68,398
1978	5	68.71	67.70	1,209.79	1,750.08	0	23,951	70,590
1978	6	78.83	77.59	560.63	811.01	0	17,467	66,111
1978	7	81.60	80.39	193.48	279.89	770	18,862	67,052
1978	8	80.40	79.72	341.38	493.84	2,343	30,383	59,532
1978	9	71.28	70.58	139.98	202.50	370	21,022	54,914
1978	10	61.73	61.67	198.95	287.81	1,926	36,994	58,167
1978	11	51.29	51.53	219.89	318.09	1,027	12,966	61,323
1978	12	41.98	42.82	744.51	1,077.01	1,962	34,828	54,252
1979	1	40.18	39.75	2,934.99	4,245.77	1,613	38,532	80,768
1979	2	29.77	29.26	1,194.08	1,727.35	5,625	34,376	72,062
1979	3	50.36	50.48	1,528.40	2,210.99	4,091	40,839	75,149

1979	4	57.07	56.06	1,056.82	1,528.80	1,632	36,637	68,398
1979	5	70.16	69.29	1,105.08	1,598.61	4,463	25,779	70,590
1979	6	77.38	76.26	523.79	757.72	2,361	66	66,111
1979	7	84.93	83.97	211.96	306.62	3,291	6,297	67,052
1979	8	79.68	78.85	751.23	1,086.74	1,445	29,288	59,532
1979	9	73.73	73.23	477.00	690.03	1,638	17,916	54,914
1979	10	60.82	61.26	1,037.85	1,501.35	2,377	22,911	58,167
1979	11	54.94	55.88	1,126.21	1,629.17	71	19,691	61,323
1979	12	45.15	45.22	661.64	957.13	972	16,671	54,252
1980	1	37.35	37.39	465.14	672.87	8,778	33,540	90,919
1980	2	35.68	35.51	289.06	418.16	10,310	27,441	110,799
1980	3	46.55	46.32	1,082.30	1,565.66	6,103	8,414	102,450
1980	4	59.54	58.30	1,608.05	2,326.21	6,773	0	90,369
1980	5	70.28	69.52	684.57	990.30	7,475	0	93,528
1980	6	75.74	74.52	390.07	564.28	6,028	0	84,340
1980	7	85.19	84.03	177.16	256.28	2,673	22,399	77,768
1980	8	82.79	82.05	154.82	223.96	2,969	24,657	88,343
1980	9	76.40	75.69	107.20	155.08	897	26,274	66,715
1980	10	59.53	59.59	179.63	259.85	1,104	19,535	72,903
1980	11	48.76	49.17	224.69	325.04	3,417	1,632	67,153
1980	12	37.96	38.75	218.68	316.34	4,008	35,191	92,937
1981	1	28.76	29.67	170.21	246.22	5,215	43,999	103,672
1981	2	45.16	45.62	693.42	1,003.10	1,242	20,269	76,249
1981	3	47.20	47.38	743.44	1,075.46	425	29,825	91,484
1981	4	59.87	60.08	602.29	871.28	242	1,485	76,795
1981	5	70.33	69.63	403.83	584.17	3,526	0	88,019
1981	6	79.06	78.74	177.45	256.70	846	0	69,119
1981	7	84.80	84.71	127.55	184.52	977	14,278	66,109
1981	8	81.33	80.49	115.74	167.43	0	12,093	47,601
1981	9	71.89	72.18	141.09	204.11	0	18,169	57,762
1981	10	59.00	59.27	172.30	249.25	232	22,492	82,710
1981	11	51.64	51.71	324.29	469.13	247	18,033	82,035
1981	12	38.39	38.50	1,212.11	1,753.44	1,205	22,345	98,063
1982	1	32.45	32.03	1,458.93	2,110.49	4,449	26,862	96,278
1982	2	39.21	39.79	1,392.45	2,014.32	1,944	23,735	87,574
1982	3	48.49	48.42	911.53	1,318.62	3,479	20,718	87,458
1982	4	57.64	56.75	937.39	1,356.03	875	9,598	74,618
1982	5	69.19	68.36	522.06	755.21	0	8,823	68,471
1982	6	72.38	72.27	1,759.16	2,544.81	47	3,361	16,291

1982	7	84.03	83.68	383.48	554.74	909	9,022	16,565
1982	8	77.57	77.51	325.39	470.71	349	8,033	13,845
1982	9	72.35	72.07	243.67	352.49	572	0	59,598
1982	10	62.46	62.32	380.22	550.02	4,034	0	73,998
1982	11	56.21	55.74	673.96	974.95	974	0	81,355
1982	12	45.47	45.62	660.36	955.28	968	0	60,464
1983	1	38.27	38.59	830.65	1,201.61	0	532	73,944
1983	2	40.49	40.38	1,523.38	2,203.73	36	2,993	68,397
1983	3	48.26	47.84	2,127.95	3,078.30	1,118	754	85,796
1983	4	58.13	58.13	2,518.22	3,642.87	76	814	122,622
1983	5	65.11	64.99	1,073.51	1,552.94	0	8,944	71,184
1983	6	80.41	80.36	581.88	841.76	902	19,203	102,919
1983	7	85.32	85.82	139.56	201.88	1,266	18,102	114,180
1983	8	81.54	82.04	190.82	276.04	2,696	27,412	116,994
1983	9	78.07	77.61	116.43	168.42	1,778	17,279	115,602
1983	10	61.91	61.48	166.98	241.55	15	9,238	77,137
1983	11	53.71	53.69	1,042.79	1,508.50	949	4,991	67,067
1983	12	40.10	40.45	1,791.28	2,591.27	2,124	17,428	99,871
1984	1	34.29	34.21	816.72	1,181.48	3,140	32,914	101,760
1984	2	45.36	45.17	1,764.70	2,552.82	430	24,559	95,474
1984	3	41.86	41.54	1,901.65	2,750.93	1,095	17,397	83,098
1984	4	56.32	56.30	1,931.39	2,793.95	338	22,699	63,649
1984	5	68.32	67.73	856.78	1,239.41	114	20,149	41,696
1984	6	79.70	79.19	1,832.23	2,650.50	2,694	32,051	76,657
1984	7	81.44	80.78	484.41	700.74	507	16,099	119,515
1984	8	82.33	82.12	198.25	286.79	2,791	30,264	116,416
1984	9	72.36	72.27	127.27	184.11	1,071	14,261	118,583
1984	10	64.23	64.60	210.07	303.89	1,351	4,896	114,187
1984	11	53.17	53.24	278.18	402.42	3,135	23,789	115,728
1984	12	46.49	46.66	397.44	574.94	52	13,823	122,662
1985	1	31.21	30.74	275.06	397.90	1,361	11,833	125,471
1985	2	40.23	40.28	483.89	700.00	457	18,073	106,859
1985	3	51.15	50.91	609.93	882.33	122	15,000	86,519
1985	4	60.61	60.72	356.79	516.14	64	16,550	113,955
1985	5	70.07	70.52	449.32	649.99	227	18,759	84,899
1985	6	73.94	73.93	287.49	415.88	109	14,931	107,303
1985	7	83.00	82.78	134.23	194.18	124	13,133	115,673
1985	8	79.04	79.32	159.54	230.80	581	13,490	112,239
1985	9	74.38	74.53	208.94	302.25	452	14,046	110,876

1985	10	65.18	64.96	173.58	251.10	3,387	11,755	114,331
1985	11	53.02	53.04	771.61	1,116.21	1,409	21,250	105,122
1985	12	38.87	39.28	540.92	782.50	1,464	28,041	124,366
1986	1	40.59	40.52	693.62	1,003.39	2,373	28,612	124,366
1986	2	35.19	35.30	968.37	1,400.85	1,441	12,648	100,404
1986	3	50.24	50.28	886.07	1,281.79	1,891	15,035	96,103
1986	4	59.57	59.04	439.43	635.69	1,871	7,832	94,563
1986	5	70.97	70.11	315.83	456.87	3,792	0	71,199
1986	6	76.15	75.57	602.32	871.31	2,817	0	22,449
1986	7	79.50	78.57	355.41	514.14	3,149	18,034	36,024
1986	8	78.13	77.62	769.86	1,113.68	2,405	6,448	55,155
1986	9	71.59	71.54	199.51	288.62	1,257	0	55,696
1986	10	62.28	62.50	218.79	316.50	0	1,155	63,170
1986	11	51.21	51.11	740.21	1,070.79	1,507	14,028	63,442
1986	12	42.51	42.82	1,985.99	2,872.94	2,807	18,258	91,008
1987	1	37.36	37.38	1,306.60	1,890.14	1,368	18,115	111,377
1987	2	38.23	37.99	625.79	905.27	1,930	15,799	111,690
1987	3	47.70	47.72	953.30	1,379.05	1,174	14,845	99,244
1987	4	56.55	56.61	2,707.54	3,916.73	1,484	15,966	101,726
1987	5	70.10	69.49	894.60	1,294.12	1,272	14,222	115,460
1987	6	78.73	77.84	229.41	331.87	868	26,354	67,453
1987	7	81.08	79.78	128.13	185.36	2,320	1,135	112,484
1987	8	79.93	78.59	83.02	120.10	1,691	29,096	115,123
1987	9	71.96	71.19	421.99	610.45	517	21,591	103,980
1987	10	61.61	61.34	289.60	418.94	95	23,719	107,495
1987	11	51.64	52.38	551.87	798.34	1,913	24,766	114,682
1987	12	43.64	43.12	790.47	1,143.49	4,245	28,902	120,325
1988	1	35.22	35.97	600.18	868.23	7,750	33,294	120,334
1988	2	40.82	40.57	1,564.22	2,262.80	3,380	24,989	112,441
1988	3	48.93	48.53	1,057.44	1,529.70	2,740	15,791	75,520
1988	4	54.68	54.36	750.26	1,085.33	2,044	13,612	85,607
1988	5	67.80	66.94	631.45	913.46	2,363	21,871	93,085
1988	6	77.93	77.04	209.82	303.53	2,464	14,814	68,083
1988	7	82.89	81.93	216.46	313.14	2,270	16,010	94,196
1988	8	83.59	82.96	116.32	168.27	4,243	22,916	106,306
1988	9	73.59	73.07	81.17	117.42	725	12,366	89,823
1988	10	59.21	58.77	89.80	129.90	3,979	12,320	99,851
1988	11	54.64	54.98	509.72	737.36	5,253	4,291	101,452
1988	12	40.81	41.23	428.34	619.63	4,262	35,783	118,789

1989	1	42.27	42.69	298.54	431.87	1,980	26,462	114,273
1989	2	37.62	37.63	440.73	637.56	7,151	34,940	109,374
1989	3	45.65	45.73	714.58	1,033.72	8,115	38,071	120,627
1989	4	55.92	55.26	1,102.83	1,595.35	4,482	27,777	101,046
1989	5	69.82	68.96	1,264.83	1,829.71	2,760	30,347	68,147
1989	6	77.70	77.16	724.79	1,048.48	1,699	9,566	96,622
1989	7	81.02	80.78	387.94	561.20	1,362	12,991	113,014
1989	8	81.51	80.81	602.39	871.41	321	13,292	95,905
1989	9	75.35	74.30	452.63	654.78	259	6,906	100,666
1989	10	65.53	64.51	976.49	1,412.59	1,251	21,408	118,199
1989	11	53.09	51.98	1,307.44	1,891.34	1,265	13,460	112,788
1989	12	28.99	29.25	469.45	679.11	8,959	34,707	126,254
1990	1	44.25	44.03	795.47	1,150.73	2,140	23,010	120,830
1990	2	44.06	43.72	1,257.03	1,818.42	652	7,892	99,382
1990	3	51.20	50.17	856.78	1,239.42	787	10,275	116,040
1990	4	57.50	56.52	1,212.68	1,754.26	2,614	17,303	64,388
1990	5	65.23	64.27	1,037.69	1,501.13	1,753	2,177	36,400
1990	6	78.08	76.72	521.80	754.83	1,767	17,816	34,777
1990	7	81.05	80.35	315.71	456.71	2,000	19,277	68,626
1990	8	81.52	80.93	680.35	984.19	2,798	21,795	102,035
1990	9	73.35	72.41	203.31	294.11	190	30,737	98,063
1990	10	67.34	66.91	490.10	708.99	396	27,652	109,213
1990	11	55.76	55.32	479.52	693.68	222	9,595	62,987
1990	12	47.00	47.25	724.82	1,048.53	0	5,513	62,414
1991	1	37.86	37.88	839.66	1,214.66	252	8,432	73,573
1991	2	43.77	43.78	819.10	1,184.91	84	1,343	91,695
1991	3	49.96	49.32	1,232.55	1,783.01	0	3,458	88,484
1991	4	61.38	60.64	865.53	1,252.07	135	4,599	75,045
1991	5	74.66	73.89	635.56	919.40	1,258	23,084	24,604
1991	6	79.33	78.80	154.32	223.24	1,901	19,104	60,137
1991	7	83.13	82.77	74.31	107.50	1,278	21,786	77,759
1991	8	82.24	81.99	243.91	352.84	3,443	33,606	107,356
1991	9	72.35	72.08	261.19	377.84	1,447	8,087	81,271
1991	10	64.65	64.82	327.53	473.80	252	0	71,889
1991	11	51.20	51.96	903.00	1,306.28	391	891	100,381
1991	12	44.12	44.71	872.82	1,262.62	1,989	7,461	101,433
1992	1	38.72	39.60	838.52	1,213.00	920	10,011	97,131
1992	2	40.40	40.76	731.18	1,057.72	1,670	5,551	89,310
1992	3	43.85	43.83	951.85	1,376.95	660	10,544	91,503

1992	4	54.61	54.54	836.41	1,209.95	431	1,984	71,109
1992	5	68.87	68.01	474.46	686.36	0	2,666	62,519
1992	6	77.69	76.92	463.30	670.21	42	3,726	81,039
1992	7	80.04	79.90	118.38	171.25	228	8,648	78,939
1992	8	78.92	78.54	215.03	311.07	69	5,112	57,136
1992	9	72.96	72.20	203.47	294.34	413	5,068	66,318
1992	10	59.45	59.59	195.34	282.58	0	0	103,978
1992	11	49.23	49.24	508.75	735.96	6	3,660	65,740
1992	12	41.07	41.20	1,904.01	2,754.35	244	5,943	60,894
1993	1	38.25	38.03	1,024.62	1,482.21	8	1,317	35,888
1993	2	33.37	33.35	1,088.79	1,575.05	243	2,239	21,976
1993	3	42.59	42.30	1,511.12	2,185.98	324	6,808	18,018
1993	4	56.82	55.97	1,849.48	2,675.47	41	1,486	11,575
1993	5	70.80	69.92	613.92	888.10	210	1,075	15,855
1993	6	78.50	77.83	183.39	265.29	1,294	422	15,595
1993	7	84.21	83.83	75.07	108.59	1,243	4,495	15,181
1993	8	83.61	82.74	47.63	68.89	1,894	4,187	11,927
1993	9	73.14	72.59	56.38	81.56	768	6,333	13,794
1993	10	60.29	60.14	90.68	131.17	105	4,552	58,059
1993	11	53.56	53.83	172.96	250.20	82	477	53,885
1993	12	40.07	39.91	819.94	1,186.12	0	0	34,555
1994	1	31.40	31.43	821.63	1,188.57	1,785	8,168	62,577
1994	2	33.86	33.65	843.86	1,220.73	123	6,925	63,009
1994	3	46.13	45.96	2,112.82	3,056.40	226	0	57,139
1994	4	61.09	60.30	1,156.75	1,673.36	0	203	49,045
1994	5	66.90	65.71	622.59	900.64	82	2,808	57,110
1994	6	79.96	78.88	261.52	378.31	310	7,348	53,955
1994	7	85.67	84.93	196.53	284.30	1,925	14,137	66,809
1994	8	80.11	79.89	211.72	306.28	419	9,170	54,317
1994	9	71.95	71.75	196.36	284.06	266	260	53,450
1994	10	63.27	63.93	140.12	202.69	0	0	49,284
1994	11	57.86	58.01	373.62	540.48	1,640	4,648	26,099
1994	12	45.42	45.72	827.96	1,197.73	443	5,950	55,210
1995	1	42.34	42.66	902.22	1,305.16	707	2,588	62,680
1995	2	37.06	37.62	755.96	1,093.57	117	3,162	65,048
1995	3	47.38	47.52	1,017.64	1,472.12	124	7	65,412
1995	4	57.47	57.04	741.80	1,073.09	227	264	15,311
1995	5	66.27	65.67	731.89	1,058.76	154	10,639	29,675
1995	6	78.13	77.67	387.87	561.09	1,782	17,204	62,271

1995	7	83.74	83.19	107.18	155.05	1,997	15,085	67,371
1995	8	82.97	82.67	89.92	130.07	1,671	19,278	53,957
1995	9	72.29	72.03	58.81	85.08	1,017	9,839	57,128
1995	10	67.20	67.21	299.57	433.36	285	544	52,126
1995	11	48.83	49.07	913.88	1,322.02	209	135	57,195
1995	12	36.41	37.06	479.88	694.20	1,269	7,563	71,818
1996	1	37.25	37.33	1,314.38	1,901.39	637	555	67,950
1996	2	37.40	37.72	1,289.15	1,864.89	578	1,805	60,445
1996	3	44.88	45.10	1,166.55	1,687.53	107	107	63,359
1996	4	57.44	57.80	1,553.12	2,246.74	121	146	61,212
1996	5	68.85	68.17	905.52	1,309.93	211	715	48,678
1996	6	77.10	76.01	376.71	544.95	81	3,989	57,936
1996	7	80.84	80.33	393.02	568.54	673	3,603	66,830
1996	8	82.15	81.17	145.45	210.41	791	9,047	71,848
1996	9	72.62	72.28	323.88	468.53	256	6,878	66,492
1996	10	62.38	61.83	938.54	1,357.70	0	5,360	48,791
1996	11	48.09	47.74	748.63	1,082.97	56	3,368	32,204
1996	12	45.62	45.72	1,797.83	2,600.75	140	1,019	44,949
1997	1	37.97	37.65	1,040.69	1,505.46	490	1,997	81,322
1997	2	44.07	44.05	993.30	1,436.91	6	231	74,558
1997	3	46.45	45.77	1,029.55	1,489.35	54	675	79,826
1997	4	55.21	55.02	1,629.60	2,357.38	150	6,569	70,505
1997	5	64.18	63.34	720.47	1,042.24	310	167	2,781
1997	6	77.62	76.90	280.29	405.47	1,895	24,156	69,018
1997	7	83.40	82.83	110.48	159.82	2,068	16,034	77,914
1997	8	79.93	79.16	110.71	160.15	143	12,398	66,645
1997	9	73.22	72.67	92.12	133.26	108	2,079	71,106
1997	10	62.69	62.50	100.02	144.69	66	3,347	80,077
1997	11	49.67	50.00	690.32	998.62	52	2,130	75,834
1997	12	42.48	43.39	601.83	870.60	1,238	12,196	82,713
1998	1	42.07	42.80	1,310.76	1,896.14	380	9,435	81,163
1998	2	44.76	45.23	1,289.71	1,865.69	0	388	61,411
1998	3	49.93	50.02	1,593.75	2,305.52	181	3,509	55,210
1998	4	59.63	59.26	1,121.90	1,622.94	67	1,244	65,793
1998	5	72.45	71.96	1,306.18	1,889.52	365	6,671	76,195
1998	6	75.60	74.95	1,192.41	1,724.94	1,490	12,011	70,034
1998	7	83.60	83.17	708.56	1,025.00	2,305	10,801	73,540
1998	8	83.05	82.63	196.02	283.56	2,154	12,264	70,613
1998	9	76.71	76.38	140.11	202.68	301	4,005	61,709

1998	10	63.35	63.35	228.50	330.55	322	3,971	46,670
1998	11	53.69	53.61	322.53	466.57	0	0	42,992
1998	12	48.42	48.15	308.10	445.70	1,152	17,754	60,800
1999	1	42.26	41.98	1,336.44	1,933.30	994	13,708	67,193
1999	2	43.73	44.06	1,256.68	1,817.92	149	524	33,714
1999	3	50.28	50.06	1,400.72	2,026.28	366	3,117	47,326
1999	4	61.41	60.89	680.34	984.18	63	18,406	56,140
1999	5	71.71	70.97	604.95	875.12	0	10,814	0
1999	6	82.96	82.18	215.79	312.16	1,941	12,697	0
1999	7	87.85	87.43	126.05	182.34	2,409	18,325	0
1999	8	82.10	81.31	45.52	65.85	245	7,045	0
1999	9	77.12	76.61	344.22	497.96	867	62,358	0
1999	10	62.94	63.29	597.32	864.09	27	7,999	0
1999	11	57.74	57.76	591.01	854.96	1,650	16,145	0
1999	12	45.64	45.78	696.23	1,007.17	0	3,959	0
2000	1	37.65	38.13	726.75	1,051.32	2,051	9,456	0
2000	2	43.16	43.35	861.86	1,246.77	279	10,876	0
2000	3	53.68	53.47	1,101.50	1,593.43	253	9,679	0
2000	4	56.00	55.90	1,171.68	1,694.95	1,412	19,130	0
2000	5	69.27	69.07	770.48	1,114.57	3,522	27,787	0
2000	6	78.15	77.91	705.61	1,020.74	915	17,900	0
2000	7	79.66	79.56	197.81	286.15	1,850	17,810	0
2000	8	79.22	79.11	196.17	283.78	1,906	22,327	0
2000	9	74.31	74.13	113.67	164.43	877	11,170	0
2000	10	63.85	63.92	106.45	153.99	732	8,248	0
2000	11	50.69	50.83	292.95	423.78	0	2,772	0
2000	12	38.63	38.73	618.68	894.99	4,976	16,669	0
2001	1	36.92	37.37	437.54	632.95	3,946	15,832	72,892
2001	2	41.43	41.35	725.57	1,049.61	398	955	60,736
2001	3	43.61	43.64	1,593.60	2,305.30	2,703	22,550	79,030
2001	4	59.38	59.39	1,092.09	1,579.82	143	2,091	68,659
2001	5	71.80	71.47	515.76	746.10	0	13,885	52,133
2001	6	80.48	80.06	947.69	1,370.93	0	8,874	70,378
2001	7	80.49	80.20	341.43	493.91	13	14,473	61,249
2001	8	83.79	83.51	350.32	506.77	0	28,514	69,614
2001	9	75.40	75.13	135.33	195.77	0	28,845	67,413
2001	10	65.40	65.41	96.83	140.07	0	19,989	31,011
2001	11	57.48	57.49	112.64	162.94	0	0	63,547
2001	12	47.92	48.28	181.31	262.28	0	14,771	77,480

2002	1	43.61	44.22	349.32	505.33	0	9,643	68,196
2002	2	45.74	46.16	603.36	872.82	0	5,956	68,230
2002	3	50.59	50.32	903.59	1,307.13	0	15,786	61,298
2002	4	63.36	62.60	773.41	1,118.82	0	958	61,648
2002	5	68.60	68.30	865.97	1,252.71	0	11,426	71,633
2002	6	76.53	76.57	493.60	714.04	0	4,554	65,504
2002	7	84.68	84.97	142.22	205.73	0	23,336	76,719
2002	8	85.47	85.25	79.57	115.10	0	34,803	60,732
2002	9	76.62	76.72	79.35	114.78	0	30,715	67,626
2002	10	61.19	61.67	106.14	153.54	0	24,110	40,631
2002	11	50.46	51.17	511.51	739.95	0	8,760	76,738
2002	12	40.71	41.34	930.48	1,346.03	0	14,465	79,674
2003	1	32.45	33.04	755.32	1,092.65	14,290	3,943	67,657
2003	2	34.40	34.78	700.48	1,013.32	18,773	4,455	71,156
2003	3	48.40	48.47	1,492.21	2,158.63	11,206	2,528	34,606
2003	4	54.32	54.34	1,308.76	1,893.25	2,948	355	0
2003	5	65.59	65.17	801.51	1,159.47	3,711	203	6,450
2003	6	74.97	74.82	1,115.22	1,613.28	4,147	582	0
2003	7	83.16	82.97	341.39	493.86	2,130	191	5,582
2003	8	83.53	83.27	402.52	582.29	3,478	105	74,284
2003	9	74.98	74.96	348.93	504.76	5,983	150	75,230
2003	10	61.67	61.86	649.23	939.17	11,778	26	67,764
2003	11	53.70	54.51	808.82	1,170.03	3,493	192	76,036
2003	12	43.72	44.16	1,404.10	2,031.17	9,423	2,315	50,351
2004	1	29.54	29.66	655.31	947.97	31,156	0	72,196
2004	2	40.24	40.97	557.39	806.32	0	0	72,438
2004	3	48.12	47.70	772.75	1,117.86	926	0	72,754
2004	4	59.48	59.49	1,727.75	2,499.37	662	0	69,611
2004	5	70.81	70.57	732.23	1,059.24	3,583	0	45,200
2004	6	77.85	77.75	236.50	342.11	1,231	0	55,349
2004	7	80.71	80.65	123.40	178.52	591	0	81,320
2004	8	80.33	79.93	226.75	328.02	767	0	72,032
2004	9	75.03	75.13	255.58	369.72	251	0	56,832
2004	10	61.42	61.56	420.97	572.58	1,984	0	62,962
2004	11	54.15	53.99	529.86	728.19	1,125	0	59,334
2004	12	44.33	44.67	1,024.98	1,435.69	5,357	0	80,761
2005	1	35.73	36.03	1,260.16	1,771.76	10,144	1,712	70,148
2005	2	40.03	40.25	1,288.39	1,812.10	685	0	61,930
2005	3	43.52	43.47	1,458.98	2,055.86	248	258	66,881

2005	4	61.65	60.96	1,502.39	2,117.89	283	115	54,875
2005	5	61.96	61.47	1,251.38	1,759.20	0	0	51,418
2005	6	80.39	79.36	600.66	829.35	7,081	-16	68,114
2005	7	83.40	83.08	213.02	275.43	9,306	0	76,607
2005	8	86.20	85.54	173.35	218.75	8,698	406	76,568
2005	9	78.83	78.85	315.26	421.53	5,169	175	67,933
2005	10	62.72	62.93	1,693.20	2,390.56	1,647	56	63,187
2005	11	56.84	56.89	1,437.06	2,024.55	0	24	60,707
2005	12	40.93	41.17	1,348.12	1,897.45	3,282	803	72,017
2006	1	45.21	45.31	1,459.05	2,055.97	0	30	61,851
2006	2	39.83	39.91	1,168.12	1,640.24	769	190	58,548
2006	3	47.43	47.37	489.44	670.42	213	0	58,925
2006	4	60.38	59.78	374.64	506.38	0	0	50,091
2006	5	67.20	66.80	1,196.25	1,680.44	102	0	53,361
2006	6	76.00	75.54	2,076.59	2,938.40	751	0	58,315
2006	7	84.24	83.77	843.61	1,176.53	1,037	5,481	67,254
2006	8	80.54	80.35	309.88	413.84	650	60	67,697
2006	9	72.55	72.30	244.54	320.48	295	0	55,078
2006	10	62.55	62.66	341.71	459.33	0	0	57,382
2006	11	56.28	56.45	1,054.08	1,477.27	61	0	56,932
2006	12	48.66	48.86	749.52	1,042.07	438	150	61,595
2007	1	41.71	42.01	751.63	1,045.08	538	0	62,082
2007	2	34.57	34.99	529.80	728.10	609	0	55,476
2007	3	47.16	47.34	1,488.63	2,098.23	2,598	0	61,827
2007	4	54.72	54.52	1,886.32	2,666.52	899	0	36,394
2007	5	71.57	70.94	970.93	1,358.46	0	0	73,232
2007	6	77.40	77.27	454.47	620.46	0	0	68,717
2007	7	83.51	83.08	213.82	276.58	1,292	1,935	71,129
2007	8	82.89	82.85	178.11	225.55	763	5,387	57,005
2007	9	77.18	76.86	147.79	182.22	636	2,509	54,299
2007	10	69.78	69.03	157.93	196.72	212	1,510	25,411
2007	11	52.27	51.72	218.22	282.87	0	0	69,715
2007	12	40.76	40.43	414.60	563.48	1,121	2,330	71,710
2008	1	41.83	41.63	660.06	914.24	0	3,201	72,003
2008	2	41.42	41.39	1,444.68	2,035.43	0	1,577	61,383
2008	3	48.25	47.92	1,505.47	2,122.30	0	773	65,632
2008	4	61.36	60.81	802.14	1,117.26	373	0	42,239
2008	5	66.39	65.91	592.47	817.66	0	4,947	73,753
2008	6	80.73	80.10	233.17	304.23	761	3,610	66,607

2008	7	85.18	84.73	200.32	257.29	268	9,223	64,538
2008	8	79.47	78.96	183.33	233.00	0	1,512	62,862
2008	9	73.36	73.07	436.24	594.40	341	564	8,427
2008	10	62.15	61.87	450.43	614.68	0	0	9,420
2008	11	51.09	50.90	671.33	930.34	0	0	35,299
2008	12	45.10	45.14	1,624.88	2,292.93	278	3,496	29,390
2009	1	32.65	32.93	1,112.05	1,560.12	436	3,466	54,569
2009	2	42.36	42.38	1,405.02	1,978.75	0	0	12,173
2009	3	46.93	46.78	1,184.94	1,664.27	0	2,064	9,257
2009	4	60.19	59.68	1,233.16	1,733.18	0	0	0
2009	5	67.81	67.25	767.66	1,067.99	0	0	0
2009	6	71.36	71.18	491.17	672.91	460	1,305	9,055
2009	7	78.65	78.21	984.05	1,377.20	210	0	7,731
2009	8	81.98	81.72	546.17	751.50	143	7,979	16,290
2009	9	72.09	72.01	540.64	743.59	0	0	0
2009	10	60.53	60.35	862.68	1,203.77	0	1,497	1,689
2009	11	56.12	55.98	870.08	1,214.34	0	1,148	0
2009	12	41.18	41.30	1,261.46	1,773.62	0	5,525	4,460
2010	1	37.04	37.24	1,045.15	1,464.52	0	539	
2010	2	39.29	39.19	1,041.35	1,459.08	0	0	
2010	3	52.42	52.51	3,020.14	4,286.70	168	0	
2010	4	63.42	63.03	2,110.44	2,986.77	0	0	
2010	5	72.46	72.15	667.27	924.54	232	7,198	
2010	6	79.06	78.84	337.58	453.42	266	6,447	
2010	7	86.21	85.96	191.69	244.95	726	17,692	
2010	8	81.95	81.82	229.74	299.33	593	9,189	
2010	9	76.03	75.94	170.18	214.22	0	7,551	
2010	10	63.64	63.67	299.98	399.70	0	1,003	
2010	11	52.62	52.75	495.42	678.97	834	11,987	
2010	12	39.54	39.50	455.76	622.30	475	3,895	

Table A3. SPSS-generated ANOVA report and table comparing 1970-1976 generation to 1977-2010 generation of Unit 8 for Cleary-Flood.

Report

Gen_Unit8

Pre_1977	Mean	N	Std. Deviation
0	1702.0232	388	2786.47425
1	13217.3690	84	10242.73392
Total	3751.3644	472	6656.41926

ANOVA Table

		Sum of Squares	df	Mean Square	F	Sig.
Gen_Unit8 * Pre_1977	Between Groups (Combined)	9.156E9	1	9.156E9	367.422	.000
	Within Groups	1.171E10	470	24920566.907		
	Total	2.087E10	471			

Table A4. SPSS-generated ANOVA report and table comparing 1970-1976 generation to 1977-2010 total generation of Unit 8 + Unit 9 for Cleary-Flood.

Report

Total_Gen

Pre_1977	Mean	N	Std. Deviation
0	12605.3918	388	11483.48140
1	14091.8571	84	10334.95904
Total	12869.9322	472	11291.51846

ANOVA Table

		Sum of Squares	df	Mean Square	F	Sig.
Total_Gen * Pre_1977	Between Groups (Combined)	1.526E8	1	1.526E8	1.197	.274
	Within Groups	5.990E10	470	1.274E8		
	Total	6.005E10	471			

Table A5. MA-SYE output for the Cleary-Flood flow proxy, upstream of Cleary-Flood and used to estimate streamflow at both power plants.

Basin Characteristic	Value	Units	Warnings
Drainage area	366.21	miles squared	The drainage area is less than 1.69 or greater than 293.91. Streamflow estimates are uncertain for all flows because drainage area is outside of the range under which the regression equations were developed.
Mean basin elevation	95.73	feet	The mean basin elevation is less than 97.64 or greater than 1849.91. Streamflow estimates are uncertain for flows greater than the 1-percent exceedence because mean basin elevation is outside of the range under which the regression equations were developed.
Average annual precipitation	48.72	inches	No warnings.
Percent of basin that is open water	5.38	percent	No warnings.
X-location at the outlet of the basin	233675.00	State Plane meters	No warnings.
Y-location at the outlet of the basin	847295.00	State Plane meters	No warnings.
Average maximum monthly temperature	15.28	degrees Celsius	No warnings.
Percent of basin that is wetlands	19.61	percent	No warnings.
Percent of basin that is sand and gravel deposits	54.39	percent	No warnings.
X-location at the center of the basin	242839.55	State Plane meters	No warnings.
Y-location at the center of the basin	857222.93	State Plane meters	No warnings.

Streamgauge code	Streamgauge number	Streamgauge name
PEEP	01115098	Peeptoad Brook at Elmdale Road near Westerly, RI

Basin Characteristic	Value for the reference streamgauge	Value at the ungauged site	Relative percent difference
Drainage area, in miles squared	4.95	366.21	194.67
Mean basin elevation, in feet	459.58	95.73	131.04
Average annual precipitation, in inches	50.31	48.72	3.22
Percent of basin that is open water	1.99	5.38	91.94
Average maximum monthly temperature, in degrees Celsius	14.95	15.28	2.21
Percent of basin that is wetlands	10.21	19.61	63.03
Percent of basin that is sand and gravel deposits	24.23	54.39	76.72
X-location, in Massachusetts State Plane meters	191182.92	233675.00	-------
Y-location, in Massachusetts State Plane meters	844703.19	847295.00	-------

Distance between ungauged site and reference streamgauge, in miles	26.45

Correlation of streamflow between ungauged site and reference streamgauge	0.93

Reference streamgauges most-correlated with the ungauged site

Reference streamgauges most-correlated with the ungauged site	Correlation
01115098 Peeptoad Brook at Elmdale Road near Westerly, RI	0.928
01108000 Taunton River near Bridgewater, MA	0.923
01109000 Wading River near Norton, MA	0.920
01105730 Indian Head River at Hanover, MA	0.902
01107000 Dorchester Brook near Brockton, MA	0.894

Table A6. Summary output used to derive streamflow values at the Cleary-Flood flow proxy point that were not provided by the MA-SYE, 2004-2010.

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.902961278
R Square	0.815339069
Adjusted R Square	0.815320116
Standard Error	278.6620897
Observations	9745

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3340501828	3340501828	43018.56652	0
Residual	9743	756568894.5	77652.5603		
Total	9744	4097070723			

	Coeffs.	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	67.5155	4.0275	16.7634	3.3450E-62	59.6207	75.4103	59.6207	75.4103
USGS	0.8481	0.0041	207.4092	0	0.8401	0.8562	0.8401	0.8562

Table A7. Correlation matrix for environmental and operational parameters at Cleary-Flood Outfall 001 used prior to MLR analysis for maximum instantaneous effluent temperature.

Correlations

		Eff_Temp_Mx	AvgHigh	SunnyDays	Rvr_Flow	Log10_Flow	TideLevel	Gen	Gen_Log10
Eff_Temp_Mx	Pearson Correlation	1	.871**	-.246	-.564**	-.622**	.555**	.142	.199
	Sig. (2-tailed)		.000	.137	.000	.000	.001	.301	.146
	N	55	55	38	55	55	30	55	55
AvgHigh	Pearson Correlation	.871**	1	-.307	-.587**	-.700**	.642**	-.018	.010
	Sig. (2-tailed)	.000		.061	.000	.000	.000	.896	.943
	N	55	55	38	55	55	30	55	55
SunnyDays	Pearson Correlation	-.246	-.307	1	.138	.100	-.379*	.407*	.289
	Sig. (2-tailed)	.137	.061		.407	.549	.039	.011	.079
	N	38	38	38	38	38	30	38	38
Rvr_Flow	Pearson Correlation	-.564**	-.587**	.138	1	.921**	-.105	.011	-.118
	Sig. (2-tailed)	.000	.000	.407		.000	.581	.937	.392
	N	55	55	38	55	55	30	55	55
Log10_Flow	Pearson Correlation	-.622**	-.700**	.100	.921**	1	-.232	-.039	-.158
	Sig. (2-tailed)	.000	.000	.549	.000		.218	.780	.250
	N	55	55	38	55	55	30	55	55
TideLevel	Pearson Correlation	.555**	.642**	-.379*	-.105	-.232	1	-.398*	-.419*
	Sig. (2-tailed)	.001	.000	.039	.581	.218		.030	.021
	N	30	30	30	30	30	30	30	30
Gen	Pearson Correlation	.142	-.018	.407*	.011	-.039	-.398*	1	.872**
	Sig. (2-tailed)	.301	.896	.011	.937	.780	.030		.000
	N	55	55	38	55	55	30	55	55
Gen_Log10	Pearson Correlation	.199	.010	.289	-.118	-.158	-.419*	.872**	1
	Sig. (2-tailed)	.146	.943	.079	.392	.250	.021	.000	
	N	55	55	38	55	55	30	55	55

**. Correlation is significant at the 0.01 level (2-tailed).
*. Correlation is significant at the 0.05 level (2-tailed).

Table A8. SPSS MLR output for model relating maximum instantaneous effluent temperature to monthly mean of daily high air temperature and log10-normalized monthly net electricity generation at Cleary-Flood Outfall 001.

Model Summary[b]

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	.891[a]	.794	.786	6.604

a. Predictors: (Constant), Gen_Log10, AvgHigh
b. Dependent Variable: Eff_Temp_Mx

Coefficients[a]

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.
		B	Std. Error	Beta		
1	(Constant)	11.667	6.911		1.688	.097
	AvgHigh	.689	.050	.869	13.798	.000
	Gen_Log10	6.977	2.310	.190	3.020	.004

a. Dependent Variable: Eff_Temp_Mx

Table A9. SPSS MLR output for model relating maximum instantaneous effluent temperature to log10-normalized monthly average of daily mean streamflow and log10-normalized monthly net electricity generation at Cleary-Flood Outfall 001.

Model Summary[b]

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	.631[a]	.398	.375	11.290

a. Predictors: (Constant), Gen_Log10, Log10_Flow
b. Dependent Variable: Eff_Temp_Mx

Coefficients

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.
		B	Std. Error	Beta		
1	(Constant)	129.039	17.247		7.482	.000
	Log10_Flow	-24.318	4.372	-.606	-5.563	.000
	Gen_Log10	3.783	3.999	.103	.946	.348

a. Dependent Variable: Eff_Temp_Mx

Table A10. Correlation matrix for environmental and operational parameters at Cleary-Flood Outfall 001 used prior to MLR analysis for maximum instantaneous ΔT.

Correlations

		Delta_T	AvgHigh	SunnyDays	Rvr_Flow	Log10_Flow	TideLevel	Gen	Gen_Log10
Delta_T	Pearson Correlation	1	-.389**	.139	.250	.275*	-.274	.321*	.365**
	Sig. (2-tailed)		.004	.412	.069	.044	.151	.018	.007
	N	54	54	37	54	54	29	54	54
AvgHigh	Pearson Correlation	-.389**	1	-.307	-.587**	-.700**	.642**	-.018	.010
	Sig. (2-tailed)	.004		.061	.000	.000	.000	.896	.943
	N	54	55	38	55	55	30	55	55
SunnyDays	Pearson Correlation	.139	-.307	1	.138	.100	-.379*	.407*	.289
	Sig. (2-tailed)	.412	.061		.407	.549	.039	.011	.079
	N	37	38	38	38	38	30	38	38
Rvr_Flow	Pearson Correlation	.250	-.587**	.138	1	.921**	-.105	.011	-.118
	Sig. (2-tailed)	.069	.000	.407		.000	.581	.937	.392
	N	54	55	38	55	55	30	55	55
Log10_Flow	Pearson Correlation	.275*	-.700**	.100	.921**	1	-.232	-.039	-.158
	Sig. (2-tailed)	.044	.000	.549	.000		.218	.780	.250
	N	54	55	38	55	55	30	55	55
TideLevel	Pearson Correlation	-.274	.642**	-.379*	-.105	-.232	1	-.398*	-.419*
	Sig. (2-tailed)	.151	.000	.039	.581	.218		.030	.021
	N	29	30	30	30	30	30	30	30
Gen	Pearson Correlation	.321*	-.018	.407*	.011	-.039	-.398*	1	.872**
	Sig. (2-tailed)	.018	.896	.011	.937	.780	.030		.000
	N	54	55	38	55	55	30	55	55
Gen_Log10	Pearson Correlation	.365**	.010	.289	-.118	-.158	-.419*	.872**	1
	Sig. (2-tailed)	.007	.943	.079	.392	.250	.021	.000	
	N	54	55	38	55	55	30	55	55

*. Correlation is significant at the 0.01 level (2-tailed).
*. Correlation is significant at the 0.05 level (2-tailed).

Table A11. SPSS MLR output for model relating maximum instantaneous ΔT of cooling water to monthly mean of daily high air temperature and log10-normalized monthly net electricity generation at Cleary-Flood Outfall 001.

Model Summary[b]

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	.539[a]	.290	.262	4.84348

a. Predictors: (Constant), Gen_Log10, AvgHigh
b. Dependent Variable: Delta_T

Coefficients[a]

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.
		B	Std. Error	Beta		
1	(Constant)	8.119	5.092		1.594	.117
	AvgHigh	-.123	.037	-.396	-3.354	.002
	Gen_Log10	5.380	1.706	.372	3.153	.003

a. Dependent Variable: Delta_T

Table A12. SPSS MLR output for model relating maximum instantaneous ΔT of cooling water to log10-normalized monthly average of daily mean streamflow and log10-normalized monthly net electricity generation at Cleary-Flood Outfall 001.

Model Summary[b]

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	.506[a]	.256	.227	4.95878

a. Predictors: (Constant), Gen_Log10, Log10_Flow
b. Dependent Variable: Delta_T

Coefficients[a]

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.
		B	Std. Error	Beta		
1	(Constant)	-17.392	7.847		-2.216	.031
	Log10_Flow	5.709	1.971	.356	2.896	.006
	Gen_Log10	6.244	1.778	.432	3.512	.001

a. Dependent Variable: Delta_T

Table A13. Correlation matrix for environmental and operational parameters at Cleary-Flood Outfall 001 used prior to MLR analysis for monthly average rate of flow in conduit.

Correlations

		Withdraw_Avg	AvgHigh	SunnyDays	Rvr_Flow	Log10_Flow	TideLevel	Gen	Gen_Log10
Withdraw_Avg	Pearson Correlation	1	.186	.152	-.117	-.121	.222	.178	.131
	Sig. (2-tailed)		.183	.376	.403	.386	.256	.203	.350
	N	53	53	36	53	53	28	53	53
AvgHigh	Pearson Correlation	.186	1	-.307	-.587**	-.700**	.642**	-.018	.010
	Sig. (2-tailed)	.183		.061	.000	.000	.000	.896	.943
	N	53	55	38	55	55	30	55	55
SunnyDays	Pearson Correlation	.152	-.307	1	.138	.100	-.379*	.407*	.289
	Sig. (2-tailed)	.376	.061		.407	.549	.039	.011	.079
	N	36	38	38	38	38	30	38	38
Rvr_Flow	Pearson Correlation	-.117	-.587**	.138	1	.921**	-.105	.011	-.118
	Sig. (2-tailed)	.403	.000	.407		.000	.581	.937	.392
	N	53	55	38	55	55	30	55	55
Log10_Flow	Pearson Correlation	-.121	-.700**	.100	.921**	1	-.232	-.039	-.158
	Sig. (2-tailed)	.386	.000	.549	.000		.218	.780	.250
	N	53	55	38	55	55	30	55	55
TideLevel	Pearson Correlation	.222	.642**	-.379*	-.105	-.232	1	-.398*	-.419*
	Sig. (2-tailed)	.256	.000	.039	.581	.218		.030	.021
	N	28	30	30	30	30	30	30	30
Gen	Pearson Correlation	.178	-.018	.407*	.011	-.039	-.398*	1	.872**
	Sig. (2-tailed)	.203	.896	.011	.937	.780	.030		.000
	N	53	55	38	55	55	30	55	55
Gen_Log10	Pearson Correlation	.131	.010	.289	-.118	-.158	-.419*	.872**	1
	Sig. (2-tailed)	.350	.943	.079	.392	.250	.021	.000	
	N	53	55	38	55	55	30	55	55

**. Correlation is significant at the 0.01 level (2-tailed).
*. Correlation is significant at the 0.05 level (2-tailed).

Table A14. SPSS MLR output for model relating monthly average rate of withdrawal to monthly mean of daily high air temperature and log10-normalized monthly net electricity generation at Cleary-Flood Outfall 001.

Model Summary[b]

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	.221[a]	.049	.011	8.53474

a. Predictors: (Constant), Gen_Log10, AvgHigh
b. Dependent Variable: Withdraw_Avg

Coefficients[a]

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.
		B	Std. Error	Beta		
1	(Constant)	-3.596	9.232		-.389	.699
	AvgHigh	.085	.065	.178	1.291	.203
	Gen_Log10	2.781	3.210	.120	.866	.390

a. Dependent Variable: Withdraw_Avg

Table A15. Correlation matrix for environmental and operational parameters at Cleary-Flood Outfall 001 used prior to MLR analysis for log10-normalized monthly average rate of flow in conduit.

Correlations

		Log10_With_avg	AvgHigh	SunnyDays	Rvr_Flow	Log10_Flow	TideLevel	Gen	Gen_Log10
Log10_With_avg	Pearson Correlation	1	.070	.245	-.027	.015	.229	.131	.087
	Sig. (2-tailed)		.619	.150	.848	.913	.242	.351	.535
	N	53	53	36	53	53	28	53	53
AvgHigh	Pearson Correlation	.070	1	-.307	-.587**	-.700**	.642**	-.018	.010
	Sig. (2-tailed)	.619		.061	.000	.000	.000	.896	.943
	N	53	55	38	55	55	30	55	55
SunnyDays	Pearson Correlation	.245	-.307	1	.138	.100	-.379*	.407*	.289
	Sig. (2-tailed)	.150	.061		.407	.549	.039	.011	.079
	N	36	38	38	38	38	30	38	38
Rvr_Flow	Pearson Correlation	-.027	-.587**	.138	1	.921**	-.105	.011	-.118
	Sig. (2-tailed)	.848	.000	.407		.000	.581	.937	.392
	N	53	55	38	55	55	30	55	55
Log10_Flow	Pearson Correlation	.015	-.700**	.100	.921**	1	-.232	-.039	-.158
	Sig. (2-tailed)	.913	.000	.549	.000		.218	.780	.250
	N	53	55	38	55	55	30	55	55
TideLevel	Pearson Correlation	.229	.642**	-.379*	-.105	-.232	1	-.398*	-.419*
	Sig. (2-tailed)	.242	.000	.039	.581	.218		.030	.021
	N	28	30	30	30	30	30	30	30
Gen	Pearson Correlation	.131	-.018	.407*	.011	-.039	-.398*	1	.872**
	Sig. (2-tailed)	.351	.896	.011	.937	.780	.030		.000
	N	53	55	38	55	55	30	55	55
Gen_Log10	Pearson Correlation	.087	.010	.289	-.118	-.158	-.419*	.872**	1
	Sig. (2-tailed)	.535	.943	.079	.392	.250	.021	.000	
	N	53	55	38	55	55	30	55	55

**. Correlation is significant at the 0.01 level (2-tailed).
*. Correlation is significant at the 0.05 level (2-tailed).

Table A16. SPSS MLR output for model relating monthly average rate of withdrawal to monthly mean of daily high air temperature and log10-normalized monthly net electricity generation at Cleary-Flood Outfall 001 for the period 2007-2010, including possible outliers.

Model Summary[b]

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	.399[a]	.159	.079	.57301

a. Predictors: (Constant), Gen_Log10, AvgHigh
b. Dependent Variable: Log10_With_avg

Coefficients[a]

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.
		B	Std. Error	Beta		
1	(Constant)	-2.376	1.224		-1.942	.066
	AvgHigh	.009	.007	.291	1.430	.167
	Gen_Log10	.651	.400	.331	1.627	.119

a. Dependent Variable: Log10_With_avg

Table A17. SPSS MLR output for model relating monthly average rate of withdrawal to monthly mean of daily high air temperature and log10-normalized monthly net electricity generation at Cleary-Flood Outfall 001 for the period 2007-2010, excluding possible outliers.

Model Summary

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	.494[a]	.244	.165	.25019

a. Predictors: (Constant), Gen_Log10, AvgHigh

Coefficients[a]

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.
		B	Std. Error	Beta		
1	(Constant)	-1.076	.551		-1.951	.066
	AvgHigh	.006	.003	.429	2.120	.047
	Gen_Log10	.292	.180	.329	1.626	.120

Model Summary

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	.494[a]	.244	.165	.25019

a. Dependent Variable: Log10_With_avg

Table A18. Correlation matrix for environmental and operational parameters at Cleary-Flood Outfall 001 used prior to MLR analysis for maximum instantaneous flow in conduit.

Correlations

		Withdraw_Mx	AvgHigh	SunnyDays	Rvr_Flow	Log10_Flow	TideLevel	Gen	Gen_Log10
Withdraw_Mx	Pearson Correlation	1	.496**	-.096	-.254	-.309*	.166	.269*	.363**
	Sig. (2-tailed)		.000	.568	.061	.022	.380	.047	.006
	N	55	55	38	55	55	30	55	55
AvgHigh	Pearson Correlation	.496**	1	-.307	-.587**	-.700**	.642**	-.018	.010
	Sig. (2-tailed)	.000		.061	.000	.000	.000	.896	.943
	N	55	55	38	55	55	30	55	55
SunnyDays	Pearson Correlation	-.096	-.307	1	.138	.100	-.379*	.407*	.289
	Sig. (2-tailed)	.568	.061		.407	.549	.039	.011	.079
	N	38	38	38	38	38	30	38	38
Rvr_Flow	Pearson Correlation	-.254	-.587**	.138	1	.921**	-.105	.011	-.118
	Sig. (2-tailed)	.061	.000	.407		.000	.581	.937	.392
	N	55	55	38	55	55	30	55	55
Log10_Flow	Pearson Correlation	-.309*	-.700**	.100	.921**	1	-.232	-.039	-.158
	Sig. (2-tailed)	.022	.000	.549	.000		.218	.780	.250
	N	55	55	38	55	55	30	55	55
TideLevel	Pearson Correlation	.166	.642**	-.379*	-.105	-.232	1	-.398*	-.419*
	Sig. (2-tailed)	.380	.000	.039	.581	.218		.030	.021
	N	30	30	30	30	30	30	30	30
Gen	Pearson Correlation	.269*	-.018	.407*	.011	-.039	-.398*	1	.872**
	Sig. (2-tailed)	.047	.896	.011	.937	.780	.030		.000
	N	55	55	38	55	55	30	55	55
Gen_Log10	Pearson Correlation	.363**	.010	.289	-.118	-.158	-.419*	.872**	1
	Sig. (2-tailed)	.006	.943	.079	.392	.250	.021	.000	
	N	55	55	38	55	55	30	55	55

**. Correlation is significant at the 0.01 level (2-tailed).
*. Correlation is significant at the 0.05 level (2-tailed).

Table A19. SPSS MLR output for model relating monthly maximum instantaneous rate of withdrawal to monthly mean of daily high air temperature and log10-normalized monthly net electricity generation at Cleary-Flood Outfall 001.

Model Summary[b]

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	.612[a]	.374	.350	8.76019

a. Predictors: (Constant), Gen_Log10, AvgHigh
b. Dependent Variable: Withdraw_Mx

Coefficients[a]

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.
		B	Std. Error	Beta		
1	(Constant)	-22.407	9.167		-2.444	.018
	AvgHigh	.297	.066	.492	4.489	.000
	Gen_Log10	10.003	3.064	.358	3.264	.002

a. Dependent Variable: Withdraw_Mx

Table A20. SPSS MLR output for model relating monthly maximum instantaneous rate of withdrawal to log10-normalzied streamflow and log10-normalized monthly net electricity generation at Cleary-Flood Outfall 001.

Model Summary[b]

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	.443[a]	.197	.166	9.92634

a. Predictors: (Constant), Gen_Log10, Log10_Flow
b. Dependent Variable: Withdraw_Mx

Coefficients[a]

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.
		B	Std. Error	Beta		
1	(Constant)	20.098	15.165		1.325	.191
	Log10_Flow	-7.873	3.844	-.258	-2.048	.046
	Gen_Log10	9.003	3.516	.322	2.561	.013

a. Dependent Variable: Withdraw_Mx

Table A21. Correlation matrix for environmental and operational parameters at Cleary-Flood Outfall 002 used prior to MLR analysis for maximum instantaneous effluent temperature.

Correlations

		Eff_Temp_Max	AvgHigh_Air	Flow_Min	Log10_Flow_min	Gen_8	Log10_Gen_8	Gen_9	Log10_Gen_9	Total_Gen	Log10_Total_Gen
Eff_Temp_Max	Pearson Correlation	1	.464**	-.388**	-.414**	.067	.015	.147	.141	.150	.263*
	Sig. (2-tailed)		.000	.000	.000	.552	.897	.192	.210	.182	.018
	N	81	81	81	81	81	81	81	81	81	81
AvgHigh_Air	Pearson Correlation	.464**	1	-.601**	-.645**	.076	.152	.344**	.205	.341**	.293**
	Sig. (2-tailed)	.000		.000	.000	.500	.177	.002	.066	.002	.008
	N	81	81	81	81	81	81	81	81	81	81
Flow_Min	Pearson Correlation	-.388**	-.601**	1	.945**	-.135	-.184	-.353**	-.315**	-.358**	-.425**
	Sig. (2-tailed)	.000	.000		.000	.230	.100	.001	.004	.001	.000
	N	81	81	81	81	81	81	81	81	81	81
Log10_Flow_min	Pearson Correlation	-.414**	-.645**	.945**	1	-.165	-.158	-.375**	-.350**	-.383**	-.419**
	Sig. (2-tailed)	.000	.000	.000		.141	.160	.001	.001	.000	.000
	N	81	81	81	81	81	81	81	81	81	81
Gen_8	Pearson Correlation	.067	.076	-.135	-.165	1	.646**	.215	.031	.334**	.340**
	Sig. (2-tailed)	.552	.500	.230	.141		.000	.053	.787	.002	.002
	N	81	81	81	81	81	81	81	81	81	81
Log10_Gen_8	Pearson Correlation	.015	.152	-.184	-.158	.646**	1	.155	-.065	.231*	.255*
	Sig. (2-tailed)	.897	.177	.100	.160	.000		.167	.564	.038	.022
	N	81	81	81	81	81	81	81	81	81	81
Gen_9	Pearson Correlation	.147	.344**	-.353**	-.375**	.215	.155	1	.653**	.992**	.774**
	Sig. (2-tailed)	.192	.002	.001	.001	.053	.167		.000	.000	.000
	N	81	81	81	81	81	81	81	81	81	81
Log10_Gen_9	Pearson Correlation	.141	.205	-.315**	-.350**	.031	-.065	.653**	1	.634**	.806**
	Sig. (2-tailed)	.210	.066	.004	.001	.787	.564	.000		.000	.000
	N	81	81	81	81	81	81	81	81	81	81

Total_Gen	Pearson Correlation	.150	.341**	-.358**	-.383**	.334**	.231*	.992**	.634**	1	.790**
	Sig. (2-tailed)	.182	.002	.001	.000	.002	.038	.000	.000		.000
	N	81	81	81	81	81	81	81	81	81	81
Log10_Total_Gen	Pearson Correlation	.263*	.293**	-.425**	-.419**	.340**	.255*	.774**	.806**	.790**	1
	Sig. (2-tailed)	.018	.008	.000	.000	.002	.022	.000	.000	.000	
	N	81	81	81	81	81	81	81	81	81	81

**. Correlation is significant at the 0.01 level (2-tailed).
*. Correlation is significant at the 0.05 level (2-tailed).

Table A22. SPSS MLR output for model relating maximum instantaneous effluent temperature to monthly mean of daily high air temperature and log10-normalized total net monthly electricity generation at Cleary-Flood Outfall 002.

Model Summary[b]

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	.483[a]	.233	.213	9.79593

a. Predictors: (Constant), Log10_Total_Gen, AvgHigh_Air
b. Dependent Variable: Eff_Temp_Max

Coefficients[a]

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.
		B	Std. Error	Beta		
1	(Constant)	62.008	6.062		10.228	.000
	AvgHigh_Air	.282	.069	.424	4.084	.000
	Log10_Total_Gen	2.314	1.730	.139	1.338	.185

a. Dependent Variable: Eff_Temp_Max

Table A23. SPSS MLR output for model relating maximum instantaneous effluent temperature to monthly mean of daily high air temperature at Cleary-Flood Outfall 002.

Model Summary[b]

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	.464[a]	.215	.205	9.84478

a. Predictors: (Constant), AvgHigh_Air
b. Dependent Variable: Eff_Temp_Max

Coefficients[a]

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.
		B	Std. Error	Beta		
1	(Constant)	67.975	4.127		16.472	.000
	AvgHigh_Air	.310	.066	.464	4.657	.000

a. Dependent Variable: Eff_Temp_Max

Table A24. Correlation matrix for environmental and operational parameters at Cleary-Flood Outfall 002 used prior to MLR analysis for log10-normalized monthly average flow in conduit.

Correlations

		With_Avg_Log10	AvgHigh_Air	Log10_Flow_min	Log10_Gen_8	Log10_Gen_9	Log10_Total_Gen
With_Avg_Log10	Pearson Correlation	1	.165	-.216	.400**	.378**	.396**
	Sig. (2-tailed)		.148	.058	.000	.001	.000
	N	78	78	78	78	78	78
AvgHigh_Air	Pearson Correlation	.165	1	-.645**	.152	.205	.293**
	Sig. (2-tailed)	.148		.000	.177	.066	.008
	N	78	81	81	81	81	81
Log10_Flow_min	Pearson Correlation	-.216	-.645**	1	-.158	-.350**	-.419**
	Sig. (2-tailed)	.058	.000		.160	.001	.000
	N	78	81	81	81	81	81
Log10_Gen_8	Pearson Correlation	.400**	.152	-.158	1	-.065	.255*
	Sig. (2-tailed)	.000	.177	.160		.564	.022
	N	78	81	81	81	81	81
Log10_Gen_9	Pearson Correlation	.378**	.205	-.350**	-.065	1	.806**
	Sig. (2-tailed)	.001	.066	.001	.564		.000
	N	78	81	81	81	81	81
Log10_Total_Gen	Pearson Correlation	.396**	.293**	-.419**	.255*	.806**	1
	Sig. (2-tailed)	.000	.008	.000	.022	.000	
	N	78	81	81	81	81	81

**. Correlation is significant at the 0.01 level (2-tailed).
*. Correlation is significant at the 0.05 level (2-tailed).

Table A25. SPSS MLR output for model relating log10-normalized average rate of withdrawal to log10-normalized net monthly energy generation in Unit 8 and log10-normalized energy generation in Unit 9 for Cleary-Flood Outfall 002.

Model Summary[b]

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	.575[a]	.331	.313	.14892

a. Predictors: (Constant), Log10_Gen_9, Log10_Gen_8
b. Dependent Variable: Log10_with_avg

Coefficients[a]

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.
		B	Std. Error	Beta		
1	(Constant)	-1.215	.052		-23.233	.000
	Log10_Gen_8	.071	.016	.435	4.588	.000
	Log10_Gen_9	.054	.012	.415	4.375	.000

a. Dependent Variable: Log10_with_avg

Table A26. Correlation matrix for environmental and operational parameters at Cleary-Flood Outfall 002 used prior to MLR analysis for log10-normalized maximum instantaneous flow in conduit.

Correlations

		Log10_with_max	AvgHigh_Air	Log10_Flow_min	Log10_Gen_8	Log10_Gen_9	Log10_Total_Gen
Log10_with_max	Pearson Correlation	1	.445**	-.315**	.243*	.339**	.331**
	Sig. (2-tailed)		.000	.004	.029	.002	.003
	N	81	81	81	81	81	81
AvgHigh_Air	Pearson Correlation	.445**	1	-.645**	.152	.205	.293**
	Sig. (2-tailed)	.000		.000	.177	.066	.008
	N	81	81	81	81	81	81
Log10_Flow_min	Pearson Correlation	-.315**	-.645**	1	-.158	-.350**	-.419**
	Sig. (2-tailed)	.004	.000		.160	.001	.000
	N	81	81	81	81	81	81
Log10_Gen_8	Pearson Correlation	.243*	.152	-.158	1	-.065	.255*
	Sig. (2-tailed)	.029	.177	.160		.564	.022
	N	81	81	81	81	81	81
Log10_Gen_9	Pearson Correlation	.339**	.205	-.350**	-.065	1	.806**
	Sig. (2-tailed)	.002	.066	.001	.564		.000
	N	81	81	81	81	81	81
Log10_Total_Gen	Pearson Correlation	.331**	.293**	-.419**	.255*	.806**	1
	Sig. (2-tailed)	.003	.008	.000	.022	.000	
	N	81	81	81	81	81	81

**. Correlation is significant at the 0.01 level (2-tailed).
*. Correlation is significant at the 0.05 level (2-tailed).

Table A27. SPSS MLR output for model relating log10-normalized maximum instantaneous flow through conduit to mean of daily high air temperature, log10-normalized net monthly energy generation in Unit 8, and log10-normalized energy generation in Unit 9 for Cleary-Flood Outfall 002.

Model Summary[b]

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	.551[a]	.304	.277	.23988

a. Predictors: (Constant), Log10_Gen_9, Log10_Gen_8, AvgHigh_Air
b. Dependent Variable: Log10_with_max

Coefficients[a]

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.
		B	Std. Error	Beta		
1	(Constant)	-1.238	.114		-10.887	.000
	AvgHigh_Air	.006	.002	.357	3.619	.001
	Log10_Gen_8	.052	.024	.208	2.148	.035
	Log10_Gen_9	.058	.020	.279	2.860	.005

a. Dependent Variable: Log10_with_max

Table A28. Correlation matrix for environmental and operational parameters at Somerset Outfall 007 used prior to MLR analysis for maximum instantaneous effluent temperature.

Correlations

		Eff_Temp_mx	AirTemp	SunDays	Flow	Flow_Log10	TideLevel	Gen
Eff_Temp_mx	Pearson Correlation	1	.945**	-.469**	-.538**	-.618**	.711**	.116
	Sig. (2-tailed)		.000	.001	.000	.000	.000	.439
	N	47	47	47	47	47	47	47
AirTemp	Pearson Correlation	.945**	1	-.472**	-.452**	-.537**	.736**	.005
	Sig. (2-tailed)	.000		.001	.001	.000	.000	.973
	N	47	47	47	47	47	47	47
SunDays	Pearson Correlation	-.469**	-.472**	1	.117	.177	-.597**	.256
	Sig. (2-tailed)	.001	.001		.432	.234	.000	.082
	N	47	47	47	47	47	47	47
Flow	Pearson Correlation	-.538**	-.452**	.117	1	.945**	-.215	-.082
	Sig. (2-tailed)	.000	.001	.432		.000	.147	.583
	N	47	47	47	47	47	47	47
Flow_Log10	Pearson Correlation	-.618**	-.537**	.177	.945**	1	-.244	-.132
	Sig. (2-tailed)	.000	.000	.234	.000		.099	.375
	N	47	47	47	47	47	47	47
TideLevel	Pearson Correlation	.711**	.736**	-.597**	-.215	-.244	1	-.254
	Sig. (2-tailed)	.000	.000	.000	.147	.099		.085
	N	47	47	47	47	47	47	47
Gen	Pearson Correlation	.116	.005	.256	-.082	-.132	-.254	1
	Sig. (2-tailed)	.439	.973	.082	.583	.375	.085	
	N	47	47	47	47	47	47	47

**. Correlation is significant at the 0.01 level (2-tailed).

Table A29. SPSS MLR output for model relating maximum instantaneous effluent temperature to monthly mean of daily high air temperature and total net monthly electricity generation at Somerset Outfall 007.

Model Summary[b]

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	.952[a]	.906	.901	4.339

a. Predictors: (Constant), Gen, AirTemp
b. Dependent Variable: Eff_Temp_mx

Coefficients[a]

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.
		B	Std. Error	Beta		
1	(Constant)	26.178	2.874		9.108	.000
	AirTemp	.830	.041	.945	20.386	.000
	Gen	.0001	.00003	.111	2.392	.021

a. Dependent Variable: Eff_Temp_mx

Table A30. SPSS MLR output for model relating maximum instantaneous effluent temperature to log10-normalized monthly mean of daily average streamflow and total net monthly electricity generation at Somerset Outfall 007.

Model Summary[b]

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	.619[a]	.383	.355	11.088

a. Predictors: (Constant), Gen, Flow_Log10
b. Dependent Variable: Eff_Temp_mx

Coefficients[a]

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.
		B	Std. Error	Beta		
1	(Constant)	150.328	15.027		10.004	.000
	Flow_Log10	-24.469	4.764	-.613	-5.136	.000
	Gen	2.093E-5	.0001	.034	.288	.775

a. Dependent Variable: Eff_Temp_mx

Table A31. Correlation matrix for environmental and operational parameters at Somerset Outfall 007 used prior to MLR analysis for maximum instantaneous ΔT.

Correlations

		Max_Delta_T	AirTemp	SunDays	Flow	Flow_Log10	TideLevel	Gen
Max_Delta_T	Pearson Correlation	1	-.207	.152	.027	.046	-.294	.300*
	Sig. (2-tailed)		.178	.323	.861	.766	.053	.048
	N	44	44	44	44	44	44	44
AirTemp	Pearson Correlation	-.207	1	-.472**	-.452**	-.537**	.736**	.005
	Sig. (2-tailed)	.178		.001	.001	.000	.000	.973
	N	44	47	47	47	47	47	47
SunDays	Pearson Correlation	.152	-.472**	1	.117	.177	-.597**	.256
	Sig. (2-tailed)	.323	.001		.432	.234	.000	.082
	N	44	47	47	47	47	47	47
Flow	Pearson Correlation	.027	-.452**	.117	1	.945**	-.215	-.082
	Sig. (2-tailed)	.861	.001	.432		.000	.147	.583
	N	44	47	47	47	47	47	47
Flow_Log10	Pearson Correlation	.046	-.537**	.177	.945**	1	-.244	-.132
	Sig. (2-tailed)	.766	.000	.234	.000		.099	.375
	N	44	47	47	47	47	47	47
TideLevel	Pearson Correlation	-.294	.736**	-.597**	-.215	-.244	1	-.254
	Sig. (2-tailed)	.053	.000	.000	.147	.099		.085
	N	44	47	47	47	47	47	47
Gen	Pearson Correlation	.300*	.005	.256	-.082	-.132	-.254	1
	Sig. (2-tailed)	.048	.973	.082	.583	.375	.085	
	N	44	47	47	47	47	47	47

*. Correlation is significant at the 0.05 level (2-tailed).
**. Correlation is significant at the 0.01 level (2-tailed).

Table A32. SPSS MLR output for model relating maximum instantaneous ΔT between effluent and intake to monthly mean of daily high air temperature and total net monthly electricity generation at Somerset Outfall 007, including a possible outlier.

Model Summary[b]

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	.370[a]	.137	.095	2.29861

a. Predictors: (Constant), Gen, AirTemp
b. Dependent Variable: Max_Delta_T

Coefficients[a]

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.
		B	Std. Error	Beta		
1	(Constant)	21.903	1.534		14.279	.000
	AirTemp	-.033	.022	-.217	-1.494	.143
	Gen	3.225E-5	.00002	.307	2.115	.041

a. Dependent Variable: Max_Delta_T

Table A33. SPSS MLR output for model relating maximum instantaneous ΔT between effluent and intake to monthly mean of daily high air temperature and total net monthly electricity generation at Somerset Outfall 007, excluding a possible outlier.

Model Summary[b]

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	.339[a]	.115	.070	1.60362

a. Predictors: (Constant), Gen, AirTemp
b. Dependent Variable: Max_Delta_T

Coefficients[a]

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.
		B	Std. Error	Beta		
1	(Constant)	22.933	1.081		21.208	.000
	AirTemp	-.030	.015	-.295	-1.983	.054
	Gen	1.314E-5	.00001	.177	1.192	.240

a. Dependent Variable: Max_Delta_T

Table A34. SPSS MLR output for model relating maximum instantaneous ΔT between effluent and intake to tidal height above MLLW and total net monthly electricity generation at Somerset Outfall 007, including a possible outlier.

Model Summary[b]

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	.374[a]	.140	.098	2.29457

a. Predictors: (Constant), Gen, TideLevel
b. Dependent Variable: Max_Delta_T

Coefficients[a]

Model		Unstandardized Coefficients B	Unstandardized Coefficients Std. Error	Standardized Coefficients Beta	t	Sig.
1	(Constant)	21.311	1.193		17.861	.000
	TideLevel	-2.416	1.565	-.232	-1.544	.130
	Gen	2.515E-5	.00002	.239	1.596	.118

a. Dependent Variable: Max_Delta_T

Table A35. SPSS MLR output for model relating maximum instantaneous ΔT between effluent and intake to tidal height above MLLW and total net monthly electricity generation at Somerset Outfall 007, including a possible outlier.

Model Summary

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	.292[a]	.085	.039	1.63026

a. Predictors: (Constant), Gen, TideLevel

Coefficients[a]

Model		Unstandardized Coefficients B	Unstandardized Coefficients Std. Error	Standardized Coefficients Beta	t	Sig.
1	(Constant)	22.103	.857		25.802	.000
	TideLevel	-1.768	1.117	-.246	-1.584	.121
	Gen	8.076E-6	.000	.109	.702	.487

a. Dependent Variable: Max_Delta_T

Table A36. Correlation matrix for environmental and operational parameters at Somerset Outfall 007 used prior to MLR analysis for monthly average flow in conduit.

Correlations

		Withdraw_avg	AirTemp	SunDays	Flow	Flow_Log10	TideLevel	Gen
Withdraw_avg	Pearson Correlation	1	.272	.127	-.252	-.324*	-.028	.707**
	Sig. (2-tailed)		.074	.413	.098	.032	.857	.000
	N	44	44	44	44	44	44	44
AirTemp	Pearson Correlation	.272	1	-.472**	-.452**	-.537**	.736**	.005
	Sig. (2-tailed)	.074		.001	.001	.000	.000	.973
	N	44	47	47	47	47	47	47
SunDays	Pearson Correlation	.127	-.472**	1	.117	.177	-.597**	.256
	Sig. (2-tailed)	.413	.001		.432	.234	.000	.082
	N	44	47	47	47	47	47	47
Flow	Pearson Correlation	-.252	-.452**	.117	1	.945**	-.215	-.082
	Sig. (2-tailed)	.098	.001	.432		.000	.147	.583
	N	44	47	47	47	47	47	47
Flow_Log10	Pearson Correlation	-.324*	-.537**	.177	.945**	1	-.244	-.132
	Sig. (2-tailed)	.032	.000	.234	.000		.099	.375
	N	44	47	47	47	47	47	47
TideLevel	Pearson Correlation	-.028	.736**	-.597**	-.215	-.244	1	-.254
	Sig. (2-tailed)	.857	.000	.000	.147	.099		.085
	N	44	47	47	47	47	47	47
Gen	Pearson Correlation	.707**	.005	.256	-.082	-.132	-.254	1
	Sig. (2-tailed)	.000	.973	.082	.583	.375	.085	
	N	44	47	47	47	47	47	47

*. Correlation is significant at the 0.05 level (2-tailed).
**. Correlation is significant at the 0.01 level (2-tailed).

Table A37. SPSS MLR output for model relating monthly average withdrawal rate to monthly mean of daily high air temperature and monthly net electricity generation for Somerset Outfall 007.

Model Summary[b]

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	.749[a]	.562	.540	11.83182

a. Predictors: (Constant), Gen, AirTemp
b. Dependent Variable: Withdraw_avg

Coefficients[a]

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.
		B	Std. Error	Beta		
1	(Constant)	79.438	7.896		10.060	.000
	AirTemp	.272	.113	.249	2.407	.021
	Gen	.001	.0001	.699	6.752	.000

a. Dependent Variable: Withdraw_avg

Table A38. SPSS MLR output for model relating monthly average withdrawal rate to log10-normalized streamflow and monthly net electricity generation for Somerset Outfall 007.Table A38. SPSS MLR output for model relating monthly average withdrawal rate to log10-normalized streamflow and monthly net electricity generation for Somerset Outfall 007.

Model Summary[b]

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	.732[a]	.535	.513	12.18151

a. Predictors: (Constant), Gen, Flow_Log10
b. Dependent Variable: Withdraw_avg

Coefficients[a]

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.
		B	Std. Error	Beta		
1	(Constant)	125.572	17.456		7.194	.000
	Flow_Log10	-9.801	5.525	-.193	-1.774	.083
	Gen	.001	.0001	.669	6.161	.000

a. Dependent Variable: Withdraw_avg

Table A39. Correlation matrix for environmental and operational parameters at Somerset Outfall 007 used prior to MLR analysis for maximum instantaneous flow in conduit.

Correlations

		Withdraw_mx	AirTemp	SunDays	Flow	Flow_Log10	TideLevel	Gen
Withdraw_mx	Pearson Correlation	1	.372*	.174	-.400**	-.436**	-.014	.307*
	Sig. (2-tailed)		.010	.242	.005	.002	.924	.036
	N	47	47	47	47	47	47	47
AirTemp	Pearson Correlation	.372*	1	-.472**	-.452**	-.537**	.736**	.005
	Sig. (2-tailed)	.010		.001	.001	.000	.000	.973
	N	47	47	47	47	47	47	47
SunDays	Pearson Correlation	.174	-.472**	1	.117	.177	-.597**	.256
	Sig. (2-tailed)	.242	.001		.432	.234	.000	.082
	N	47	47	47	47	47	47	47
Flow	Pearson Correlation	-.400**	-.452**	.117	1	.945**	-.215	-.082
	Sig. (2-tailed)	.005	.001	.432		.000	.147	.583
	N	47	47	47	47	47	47	47
Flow_Log10	Pearson Correlation	-.436**	-.537**	.177	.945**	1	-.244	-.132
	Sig. (2-tailed)	.002	.000	.234	.000		.099	.375
	N	47	47	47	47	47	47	47
TideLevel	Pearson Correlation	-.014	.736**	-.597**	-.215	-.244	1	-.254
	Sig. (2-tailed)	.924	.000	.000	.147	.099		.085
	N	47	47	47	47	47	47	47
Gen	Pearson Correlation	.307*	.005	.256	-.082	-.132	-.254	1
	Sig. (2-tailed)	.036	.973	.082	.583	.375	.085	
	N	47	47	47	47	47	47	47

*. Correlation is significant at the 0.05 level (2-tailed).
**. Correlation is significant at the 0.01 level (2-tailed).

Table A40. SPSS MLR output for model relating monthly maximum instantaneous withdrawal rate to monthly mean of daily high air temperature and monthly net electricity generation for Somerset Outfall 007.

Model Summary[b]

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	.481[a]	.231	.196	18.415665

a. Predictors: (Constant), Gen, AirTemp
b. Dependent Variable: Withdraw_mx

Coefficients[a]

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.
		B	Std. Error	Beta		
1	(Constant)	99.342	12.200		8.143	.000
	AirTemp	.484	.173	.370	2.800	.008
	Gen	.0003	.0001	.305	2.308	.026

a. Dependent Variable: Withdraw_mx

Table A41. SPSS MLR output for model relating monthly maximum instantaneous withdrawal rate to log10-normalized streamflow and monthly net electricity generation for Somerset Outfall 007.

Model Summary[b]

Model	R	R Square	Adjusted R Square	Std. Error of the Estimate
1	.504[a]	.254	.220	18.145105

a. Predictors: (Constant), Gen, Flow_Log10
b. Dependent Variable: Withdraw_mx

Coefficients[a]

Model		Unstandardized Coefficients		Standardized Coefficients	t	Sig.
		B	Std. Error	Beta		
1	(Constant)	201.081	24.591		8.177	.000
	Flow_Log10	-23.904	7.797	-.403	-3.066	.004
	Gen	.0002	.0001	.254	1.930	.060

a. Dependent Variable: Withdraw_mx

Table A42. Air temperature predictions by month (2011-2030).

Year	Mo.	A1fi (high), °F	B1 (low), °F	Average
2011	01	33.3158	36.7394	35.0276
2011	02	38.3414	39.2576	38.7995
2011	03	45.014	46.1804	45.5972
2011	04	58.352	57.2756	57.8138
2011	05	66.4322	68.7362	67.5842
2011	06	77.5094	79.0628	78.2861
2011	07	83.1776	83.7716	83.4746
2011	08	81.1004	81.0392	81.0698
2011	09	71.2922	72.7772	72.0347
2011	10	62.5622	61.9268	62.2445
2011	11	48.0902	48.1964	48.1433
2011	12	38.1254	35.6576	36.8915
2012	01	33.2402	30.182	31.7111
2012	02	42.5984	40.9892	41.7938
2012	03	46.1714	48.6284	47.3999
2012	04	59.2088	58.4798	58.8443
2012	05	69.5354	66.8534	68.1944
2012	06	77.5544	77.1782	77.3663
2012	07	81.905	81.6494	81.7772
2012	08	81.2966	79.16	80.2283
2012	09	71.6342	73.391	72.5126
2012	10	60.1394	62.5118	61.3256
2012	11	49.7354	52.8368	51.2861
2012	12	42.6326	39.4628	41.0477
2013	01	33.062	38.0408	35.5514
2013	02	38.4656	34.5974	36.5315
2013	03	45.1832	46.7672	45.9752
2013	04	56.804	59.3852	58.0946
2013	05	69.0512	67.3862	68.2187
2013	06	78.8684	79.1132	78.9908
2013	07	82.562	83.4206	82.9913
2013	08	82.5944	81.455	82.0247
2013	09	71.0186	72.2102	71.6144
2013	10	63.698	64.4144	64.0562
2013	11	54.4352	52.2572	53.3462
2013	12	40.7642	43.4732	42.1187
2014	01	33.908	34.9124	34.4102

2014	02	36.4154	35.33	35.8727
2014	03	41.3402	43.8368	42.5885
2014	04	55.1966	57.3242	56.2604
2014	05	66.3386	64.9796	65.6591
2014	06	76.361	78.404	77.3825
2014	07	81.7664	81.851	81.8087
2014	08	80.1788	81.6026	80.8907
2014	09	74.1236	74.3864	74.255
2014	10	66.2576	65.6546	65.9561
2014	11	52.3778	48.5834	50.4806
2014	12	44.8232	43.6568	44.24
2015	01	31.874	39.6482	35.7611
2015	02	39.6068	36.9284	38.2676
2015	03	46.3334	46.922	46.6277
2015	04	53.996	54.8276	54.4118
2015	05	67.4906	67.109	67.2998
2015	06	76.7066	77.5094	77.108
2015	07	83.3108	79.9916	81.6512
2015	08	82.4306	80.6684	81.5495
2015	09	75.5942	71.906	73.7501
2015	10	60.971	63.1202	62.0456
2015	11	53.3336	47.606	50.4698
2015	12	43.5938	40.1648	41.8793
2016	01	38.7248	36.1508	37.4378
2016	02	36.1742	35.438	35.8061
2016	03	47.8796	46.9274	47.4035
2016	04	58.874	57.6842	58.2791
2016	05	69.4022	67.928	68.6651
2016	06	78.3428	77.7596	78.0512
2016	07	84.6464	81.1976	82.922
2016	08	82.6448	79.9088	81.2768
2016	09	76.2098	72.023	74.1164
2016	10	65.0714	59.1152	62.0933
2016	11	51.341	49.6076	50.4743
2016	12	37.7762	38.0606	37.9184
2017	01	32.3186	35.663	33.9908
2017	02	37.904	39.0866	38.4953
2017	03	46.724	47.2478	46.9859
2017	04	57.4412	58.4168	57.929

2017	05	68.999	69.5984	69.2987
2017	06	77.7398	79.3058	78.5228
2017	07	84.722	82.9814	83.8517
2017	08	81.671	80.5226	81.0968
2017	09	73.1246	74.2532	73.6889
2017	10	62.816	62.0492	62.4326
2017	11	49.5176	51.611	50.5643
2017	12	43.2176	37.805	40.5113
2018	01	35.1032	34.286	34.6946
2018	02	40.4132	42.9512	41.6822
2018	03	47.6798	45.5396	46.6097
2018	04	57.515	56.2406	56.8778
2018	05	69.2186	70.5848	69.9017
2018	06	76.109	78.3086	77.2088
2018	07	81.9302	82.6214	82.2758
2018	08	81.7808	82.4036	82.0922
2018	09	72.0374	72.3506	72.194
2018	10	61.5416	61.3256	61.4336
2018	11	52.2734	48.9956	50.6345
2018	12	40.4672	44.0978	42.2825
2019	01	32.6246	39.1388	35.8817
2019	02	39.227	39.5654	39.3962
2019	03	45.1202	44.2166	44.6684
2019	04	57.2432	59.9126	58.5779
2019	05	65.2532	69.4904	67.3718
2019	06	75.3602	76.721	76.0406
2019	07	81.1454	82.1804	81.6629
2019	08	80.258	84.1802	82.2191
2019	09	73.3694	73.1894	73.2794
2019	10	61.4372	65.813	63.6251
2019	11	50.2718	50.2394	50.2556
2019	12	38.5052	41.9288	40.217
2020	01	36.3866	37.7042	37.0454
2020	02	37.3694	35.9438	36.6566
2020	03	44.465	44.0276	44.2463
2020	04	58.3988	59.6282	59.0135
2020	05	66.497	69.4022	67.9496
2020	06	77.2304	78.1376	77.684
2020	07	80.6396	82.0148	81.3272

2020	08	81.0086	81.5054	81.257
2020	09	73.4684	74.7122	74.0903
2020	10	59.945	61.2752	60.6101
2020	11	49.5806	49.1324	49.3565
2020	12	36.977	38.2028	37.5899
2021	01	38.2136	37.2686	37.7411
2021	02	37.8284	39.155	38.4917
2021	03	46.2074	46.3316	46.2695
2021	04	56.516	58.9946	57.7553
2021	05	65.579	70.1528	67.8659
2021	06	79.34	77.7254	78.5327
2021	07	84.425	83.1398	83.7824
2021	08	82.3478	81.707	82.0274
2021	09	74.1182	75.5708	74.8445
2021	10	64.5548	60.3284	62.4416
2021	11	48.4142	51.0278	49.721
2021	12	40.3232	41.3924	40.8578
2022	01	30.992	35.0726	33.0323
2022	02	38.6222	41.8244	40.2233
2022	03	42.9026	45.356	44.1293
2022	04	56.0156	55.283	55.6493
2022	05	67.7192	72.5378	70.1285
2022	06	76.2458	77.8154	77.0306
2022	07	82.958	80.645	81.8015
2022	08	80.5424	79.403	79.9727
2022	09	75.5564	71.7188	73.6376
2022	10	63.041	63.482	63.2615
2022	11	52.2968	48.9668	50.6318
2022	12	41.9882	41.0504	41.5193
2023	01	35.3156	36.707	36.0113
2023	02	44.591	32.5976	38.5943
2023	03	43.0322	43.9484	43.4903
2023	04	60.6992	58.9784	59.8388
2023	05	71.0816	71.7548	71.4182
2023	06	79.799	76.577	78.188
2023	07	82.967	81.482	82.2245
2023	08	83.7032	82.4486	83.0759
2023	09	72.293	74.0588	73.1759
2023	10	62.0168	65.2406	63.6287

2023	11	51.062	50.6804	50.8712
2023	12	42.6884	40.856	41.7722
2024	01	36.9068	37.004	36.9554
2024	02	37.2902	37.4	37.3451
2024	03	44.033	43.385	43.709
2024	04	56.795	56.003	56.399
2024	05	66.4214	68.0162	67.2188
2024	06	80.2724	77.2736	78.773
2024	07	85.4276	83.4764	84.452
2024	08	82.895	82.8914	82.8932
2024	09	73.9544	73.6466	73.8005
2024	10	60.0152	66.6338	63.3245
2024	11	51.98	52.673	52.3265
2024	12	41.4392	40.2206	40.8299
2025	01	38.417	37.5746	37.9958
2025	02	40.9982	35.5118	38.255
2025	03	43.115	46.544	44.8295
2025	04	55.8968	58.6094	57.2531
2025	05	66.839	69.7424	68.2907
2025	06	78.6938	77.0234	77.8586
2025	07	82.7474	81.2498	81.9986
2025	08	82.7564	81.6782	82.2173
2025	09	74.4692	76.6184	75.5438
2025	10	62.0438	66.2738	64.1588
2025	11	51.6974	51.5876	51.6425
2025	12	38.165	40.2044	39.1847
2026	01	37.0328	31.613	34.3229
2026	02	36.5648	35.7854	36.1751
2026	03	43.763	48.137	45.95
2026	04	57.4628	55.9022	56.6825
2026	05	70.331	67.298	68.8145
2026	06	76.4366	74.4548	75.4457
2026	07	82.9274	80.7368	81.8321
2026	08	81.6242	80.5874	81.1058
2026	09	72.9068	75.2684	74.0876
2026	10	64.274	60.44	62.357
2026	11	51.8684	51.1016	51.485
2026	12	39.4754	38.7482	39.1118
2027	01	32.9	37.8914	35.3957

2027	02	38.1074	38.3828	38.2451
2027	03	46.7888	45.0068	45.8978
2027	04	57.9974	59.891	58.9442
2027	05	70.961	68.6912	69.8261
2027	06	79.8332	80.042	79.9376
2027	07	82.8194	83.399	83.1092
2027	08	79.826	81.275	80.5505
2027	09	72.3542	72.9212	72.6377
2027	10	64.9148	62.9222	63.9185
2027	11	51.4814	47.372	49.4267
2027	12	40.1234	38.8256	39.4745
2028	01	39.7976	39.5312	39.6644
2028	02	42.1988	40.5284	41.3636
2028	03	44.9924	44.5874	44.7899
2028	04	58.586	59.2682	58.9271
2028	05	70.2374	69.2312	69.7343
2028	06	79.07	78.0296	78.5498
2028	07	83.7482	81.8096	82.7789
2028	08	83.579	83.0192	83.2991
2028	09	74.354	73.8482	74.1011
2028	10	63.6944	62.6162	63.1553
2028	11	53.843	48.524	51.1835
2028	12	37.6178	38.9066	38.2622
2029	01	36.3866	36.8168	36.6017
2029	02	40.5482	38.6384	39.5933
2029	03	47.3018	47.7608	47.5313
2029	04	58.0262	57.299	57.6626
2029	05	69.773	72.1922	70.9826
2029	06	78.7784	79.5254	79.1519
2029	07	83.3198	81.7736	82.5467
2029	08	81.8564	82.0868	81.9716
2029	09	74.4386	73.5962	74.0174
2029	10	66.9236	60.4256	63.6746
2029	11	50.7182	47.426	49.0721
2029	12	40.4636	36.536	38.4998
2030	01	36.6422	33.7244	35.1833
2030	02	40.082	34.1096	37.0958
2030	03	44.9942	43.8512	44.4227
2030	04	61.4678	57.8048	59.6363

2030	05	68.0504	67.766	67.9082
2030	06	78.2564	78.8162	78.5363
2030	07	82.0238	82.0166	82.0202
2030	08	82.0472	82.85	82.4486
2030	09	72.5684	75.785	74.1767
2030	10	64.1624	62.7458	63.4541
2030	11	48.3242	52.5722	50.4482
2030	12	41.6462	42.9602	42.3032

Table A43. Listing of individuals whose testimony was used in crafting solutions, including their area of expertise and their professional affiliation.

Name	Title	Affiliation	Conference	Format
Cunningham, William L.	Hydrologist	USGS Office of Ground Water	GWPC	Presentation
Diehl, Tim	Hydrologist	USGS Tennessee Water Science Center	GWPC	Group discussion, group interview
Harris, Melissa	Physical Scientist	USGS Tennessee Water Science Center	GWPC	Group discussion, group interview
Harto, Chris	Energy and Environmental Analyst	Argonne National Lab	GWPC	Group discussion
Hightower, Michael	Energy Systems Analyst	Sandia National Lab	ASME	Panel discussion, interview, keynote address
Hutson, Susan	Hydrologist	USGS Maryland Water Science Center	GWPC	Group discussion
King, Carey	Mechanical Engineer	UT Austin	ASME	Panel discussion
Kresic, Neven	Hydrogeologist	AMEC, E&I, Inc.	GWPC	Presentation
Kuniansky, Eve	Hydrologist	USGS Southeast Regional Area	GWPC	Group discussion
LeGaludec, Olivier	Engineer	ALSTOM	ASME	Panel discussion
Macknick, Jordan	Energy and Environmental Analyst	National Renewable Energy Laboratory	GWPC, ASME	Group discussion, panel discussion
McFarlane, Joanna	Physical Chemist	Oakridge National Lab	GWPC	Group discussion
Murphy, Jennifer	Hydrologist	USGS	GWPC	Group discussion, group interview, presentation
Noble, Russell	Utility Researcher	Southern Company	ASME	Panel discussion
Shrier, Cat	Civil Engineering	Watercat Consulting, LLC	GWPC	Interview
Shuster, Erik	Energy Analyst	NETL	GWPC	Group discussion
Skaff, William	Policy Manager	Nuclear Energy Institute	GWPC	Group discussion, interview
Webber, Michael	Mechanical Engineer	UT Austin	ASME	Keynote address
Zammit, Kent	Senior Program Manager	EPRI	ASME	Panel discussion

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